STATE OF OHIO
MICHAEL V. DISALLE, Governor
DEPARTMENT OF NATURAL RESOURCES
HERBERT B. EAGON, Director
DIVISION OF GEOLOGICAL SURVEY
RALPH J. BERNHAGEN, Chief

INFORMATION CIRCULAR

No. 29

Contributions To The OIL And GAS INDUSTRY In Ohio

A COLLECTION OF PAPERS
PRESENTED AT THE FIFTH WINTER MEETING OF THE
OHIO OIL AND GAS ASSOCIATION IN COLUMBUS, OHIO
MARCH 3, 1961

COLUMBUS

1961

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TABLE OF CONTENTS

ILLUSTRATIONS

TABLES

GAS RECYCLING AND SLIM HOLE COMPLETIONS IN THE CLINTON SAND

By Brady G. Johnson

INTRODUCTION

GAS RECYCLING AND SLIM HOLE COMPLETIONS IN THE CLINTON SAND

The road to faster pay out, greater ultimate recovery, and future reductions in the cost of Clinton completions is open to the Ohio producer by the application of gas recycling, and the development and refinement of slim hole completion methods and equipment.

The main objective or purpose of this paper will therefore be to present a review of information and experiences in both "Slim Hole" completions and "Gas Recycling" operations of the past two years, conducted on some of Natol Corporation's Clinton leases, and is intended to be helpful in any future consideration or efforts you may have or make in these areas.

Every Ohio operator present knows that he must be on the alert for any new ideas, developments, or experiences which will help in the struggle against diminishing revenue per dollar spent. The trend today remains unchanged from that of the past several years, that is, rising costs, horizontal oil prices, and greater competition for the more prospective areas available for development.

The oil producing industry during recent years has greatly intensified efforts toward increased economies in completions and operations. These efforts are in evidence by news of triple, quadruple and, more recently, quintuple completions. Also, progress in the more advanced methods of secondary recovery, such as miscible phase displacement and in situ combustion, is being made.

The Ohio operator cannot economically consider these newer, more complicated and expensive methods; however, he can and should consider and apply, where feasible, gas recycling to certain of his present properties and, as current salvageable materials are depleted, be aware of the possible savings through slim hole completion methods and equipment.

Gas recycling certainly is not new. Actually, Ohio producers, from an historical standpoint, can be proud of the fact that the first recorded instance in which an effort was made to stimulate recovery of petroleum by injecting compressed gas into an oil reservoir was in 1903 in the Macksburg pool in Southeastern Ohio. This first test, and another commercial project in 1911, was made by I. L. Dunn and two associates, O. C. Dunn and H. E. Smith. These projects, in the vicinity of Marietta, Ohio, led early writers to refer to the method as the "Smith-Dunn" or "Marietta" process.

Several gas recycling projects are currently operating in Ohio. Oxford Oil of Zanesville, Waverly Oil of Newark and Natol Corporation are now operating a total of four projects. There are no doubt others unknown to the writer.

Testing of slim hole completion methods and equipment in Ohio has occurred only in the last two or three years. During 1960 the Pure Oil Company rotary drilled a Clinton well in Clark Township, Coshocton

County and had 2-1/2" casing on location. The well was dry and abandoned, however, plans were to complete with 1-1/4" tubing and 1/2" sucker rods. Natol Corporation, in the latter part of 1958, ran a temporary test installation of 2-1/2" casing on a packer inside of the 5-1/2" production string, and, about six months later, permanently completed a well with slim hole equipment. A paper on the first temporary test installation was presented to this Ohio Oil and Gas Association meeting in January of 1959. Natol also is dual producing Clinton gas and Medina oil from depths of 4100' and 4200', respectively, in a cemented and perforated string of 3" casing.

The results of Natol projects indicate that gas recycling, applied under certain conditions, can profitably increase and maintain recovery rates from the Clinton sand, and that any Clinton well can be successfully completed, equipped and produced in 2-1/2" or 3" casing with presently available tools and equipment.

The discussion in this paper will be limited to Natol's experience only on projects of slim hole completion and gas recycling undertaken on three adjoining leases in Monroe Township, Coshocton County.

The following portion of this paper will present and cover these projects in two main parts. Part I will discuss the slim hole test installations, both temporarily and permanently completed, and Part II will deal with gas recycling. Methods, equipment, results, economics and problems will be presented and discussed in each case.

PART I SLIM HOLE TEST INSTALLATIONS

Mentioned previously, Natol Corporation, in 1958, initiated a project to consider the design and testing of scaled down slim hole production equipment, first on a temporary basis and then, further, to permanently complete a Clinton well utilizing the experience gained earlier.

Temporary Packer Installation.

The goal of this first installation was to arrive at the minimum practical size of production equipment, taking into consideration the production characteristics of the Clinton formation, to test it under difficult conditions, and yet, in the event of failure, be able to salvage all equipment without jeopardizing the well utilized for the test.

It was decided that the selected slim hole casing string would be installed on a packer inside of a conventionally equipped Clinton well.

Casing and Tubing: After considering the various coupling and thread strengths in relation to the depth of Clinton wells, 2-1/2" regular ten-thread tubing was selected for casing, and J55, 1-1/4" upset for tubing.

Pumping Equipment:

1. Rods and Wire Line System. Since 1/2" sucker rods were not yet available to the producer, a 5/8", 6 x 7 regular left lay steel core wire line was chosen in their absence. The left lay line was preferred because of its tendency to tighten any threaded joints in the system. The breaking strength of the line was rated at 15 ton which

would provide a seven-to-one safety factor. The wire line passed through a 1-1/8" O.D. hollow polish rod at the well head and, at the bottom, was attached with a rope socket to three 1" O.D., 18' sinkers with 5/8" box and pins.

2. Bottom-Hole Pump. A 1-1/16" insert pump barrel was adapted to the 1-1/4" tubing and its double-valved plunger was subsequently attached to the wire line sinkers.

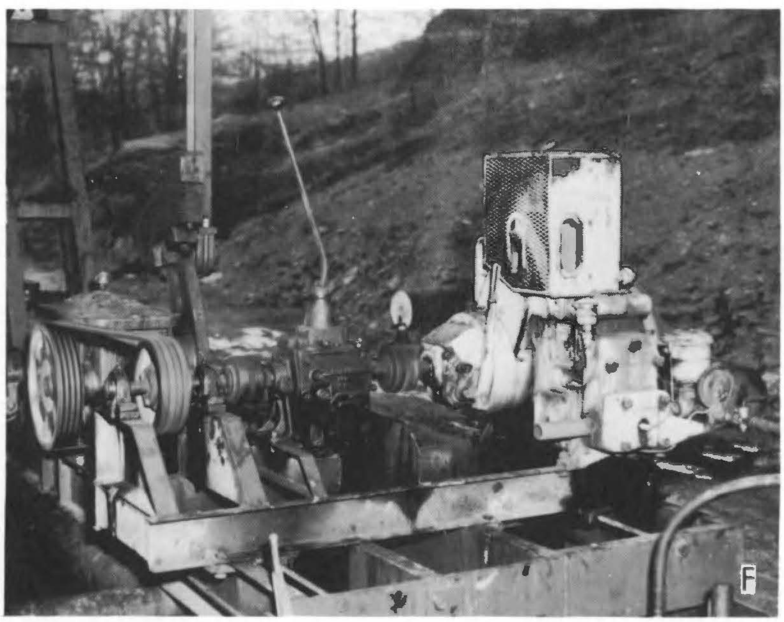
3. Pumping Unit. Both hydraulic and beam units were con-considered, however, maintenance and simplicity favored the selection of a beam unit. The stroke of a 34" unit was lengthened to 48" by shifting the beam and installing a specially built, oversized horsehead. A range of strokes per minute from one to twenty was available through the installation of a 1948 Ford, four-speed transmission between engine and gear reducer.

4. Other Equipment. The casing head was made from a 2-1/2" nipple, two 1-1/4" outlets and two flanges; also an 18', 1-1/4" gas anchor was constructed. The wire line was connected to the horsehead bridle with a special clamp.

The above equipment was installed in a 3400' depth well, being the No. 2 well shown in Figure 1.

Operational Results: After testing and adjustments, the well was placed on 24-hour operation at only 8 or 9 strokes per minute. Production averaged around 125 barrels per week for the first one and a half years,

SLIM HOLE TEMPORARY TEST WELL NO. 2



after which time considerable difficulty in pumping was encountered due to the high gas-oil ratios resulting from the gas recycling project subsequently undertaken on the lease. The wire line performed very well for about one year at which time the pump became inoperative and, when pulled, was found to contain wire line wickers. These were removed and the line and pump returned to production for another three months. Trouble was again encountered. Inspection of the wire line revealed that very little external wear was occurring and that failure was taking place in the steel wire line center throughout its entire length. By this time, 1/2" sucker rods were available and installed in the well.

The 1/2" sucker rods gave satisfactory service, without failure, for the next several months; however, as mentioned earlier, pumping became increasingly difficult due to high gas-oil ratios and just recently the rods were removed and a 1-1/4" Garrett piston lift was installed. The well is now flowing its production.

<u>Permanent Completion.</u>

After approximately six months successful operation of the No. 2 temporary test well, the drilling and permanent completion of a slim hole equipped well was undertaken and completed on March 3, 1959.

The well was drilled and cased in the manner used during the old shooting days. Five and one-half inch pipe was set through the Big Lime and the well drilled in with only a small show of oil. Total depth was 3300 feet.

<u>The 2-1/2" Production String:</u> It was decided that the 2-1/2" casing string would be cemented in top of the Clinton sand with a 4-1/2" O. D. perforated liner attached to the bottom, setting through and covering the entire Clinton section. To accomplish this, a 3" Halliburton "Full-Flow Packer Shoe," threaded at the bottom end for a 3" nipple, was attached to the 2-1/2" string. This tool, incidentally, was used because, after cementing, a plug seats, shears a pin, closes cementing ports and releases the entire center sleeve of the tool which then drops to bottom. A full opening diameter results and no further drilling-out is required. The 3" nipple just mentioned served two main purposes. First, in order to prevent cement contamination of the formation in case of packer failure, the nipple carried a metal petal basket below the Halliburton tool, and second, by means of an adapter, provided a connection between the 2-1/2" string with attached Halliburton tool and the liner. Diagram I and II shows the equipment and operation.

No difficulty was encountered in the cementing of the casing. The volume required to fill the annular space a safe distance below the 5-1/2" casing seat was calculated and only eight sacks were used. This was done to permit removal of the 5-1/2" without loss. The Halliburton tool packing element set properly and, after sufficient cement was displaced above it, the top plug seated, pressure was applied, pins sheared and the internal sleeve dropped to bottom. A round trip with a 1-3/4" O. D. sand pump showed this to be the case.

OPERATING DIAGRAM
FULL-FLOW PACKER SHOE

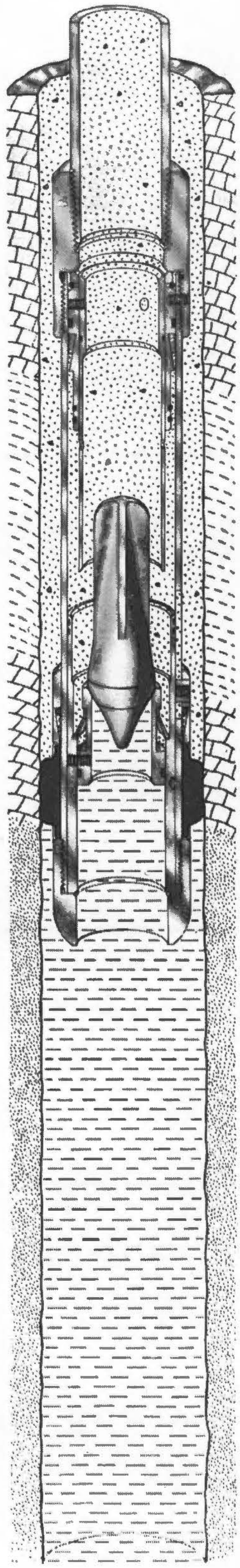


FIG. 1

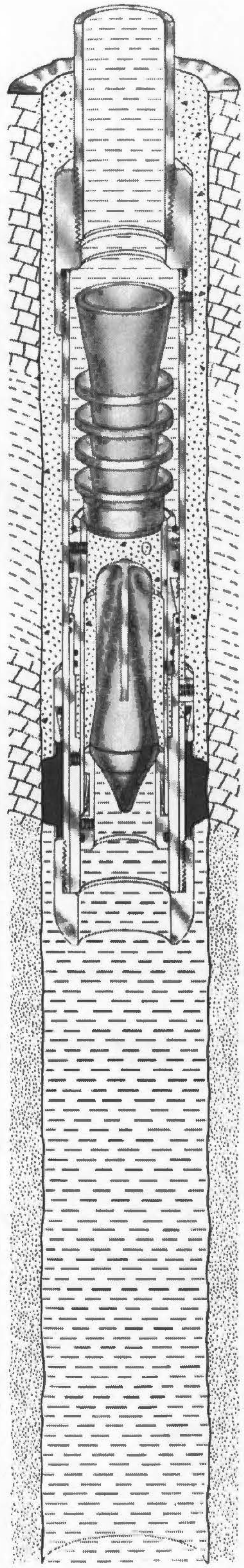


FIG. 2

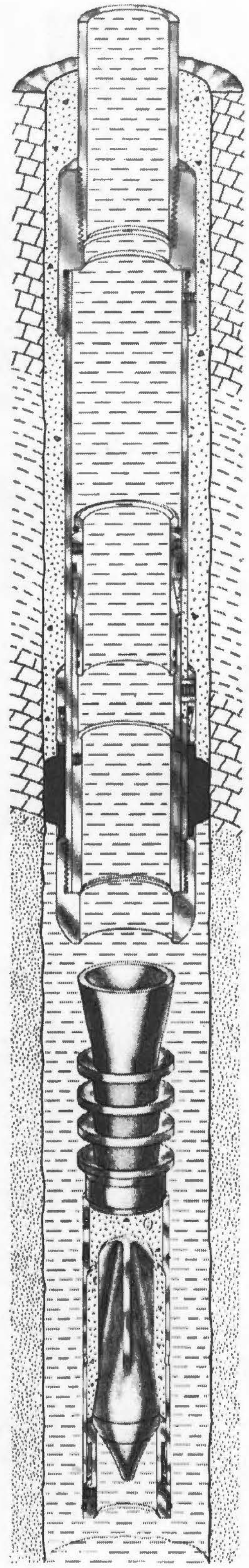


FIG. 3

DIAGRAM 1

SLIM HOLE COMPLETION CEMENTING AND LINER DIAGRAM

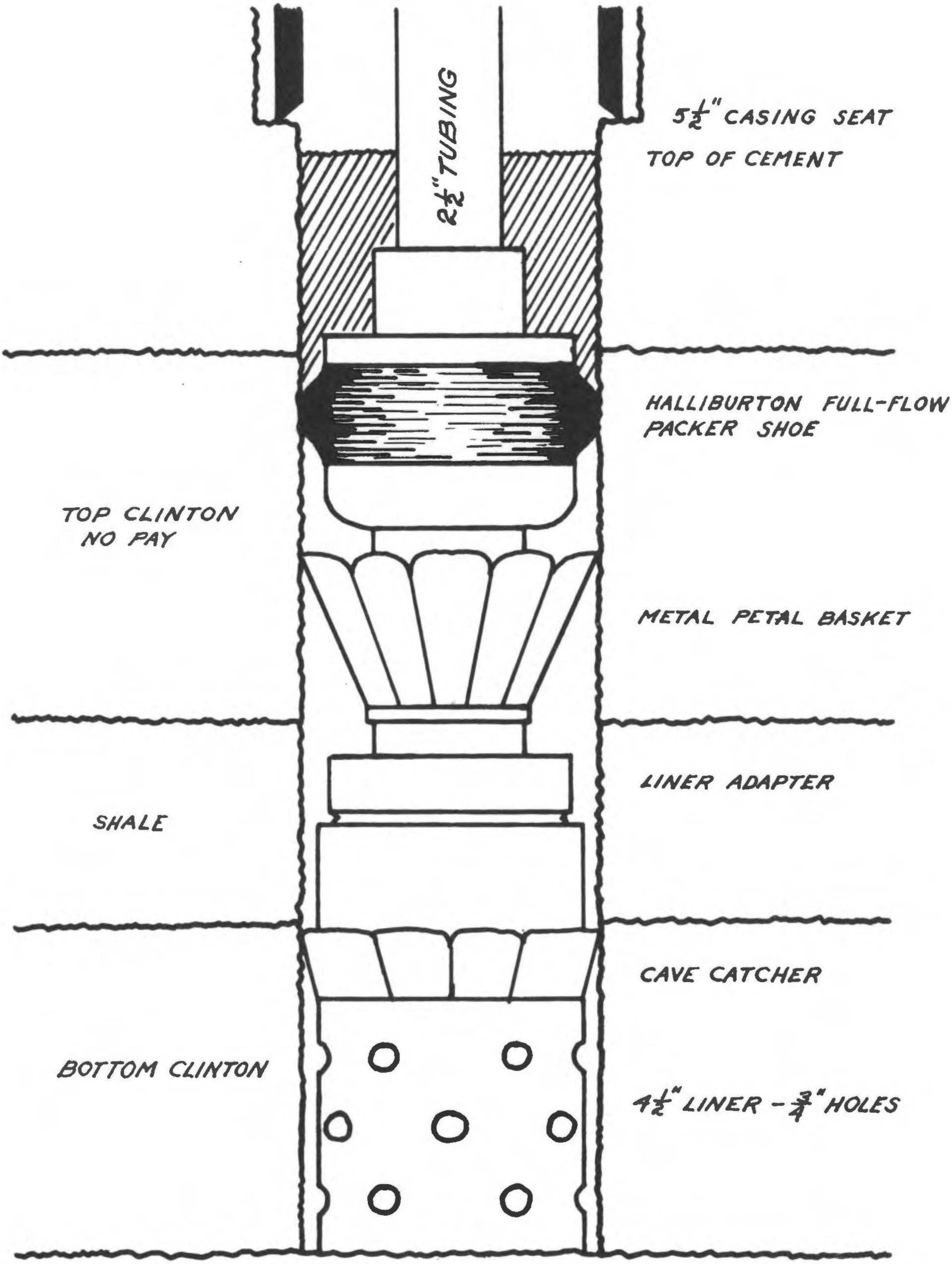
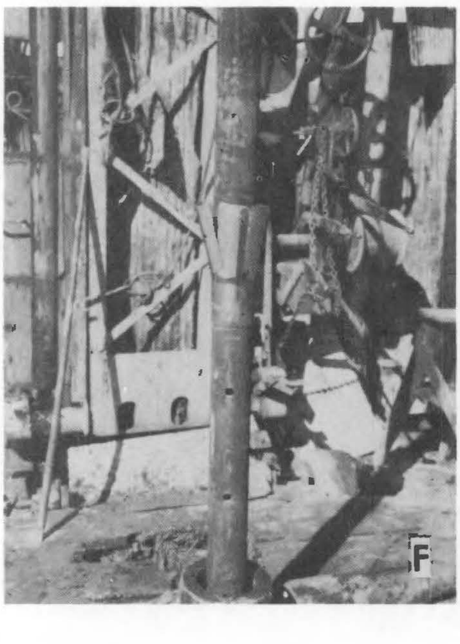
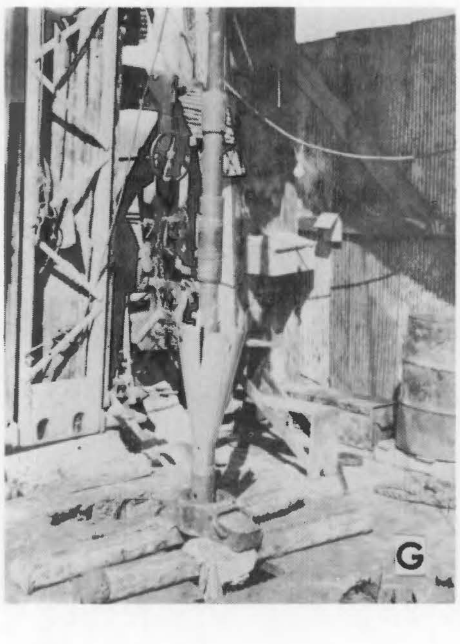


DIAGRAM II

PICTURES OF SLIM HOLE
PERMANENT COMPLETION - TEST WELL NO. 6 (MOORE #7)

Showing cementing of $2\frac{1}{2}$" and liner





Fracturing: After cementing, preparations were begun for fracturing. Considerably more oil than that normally required was moved onto location for the purpose of making several injection rate tests. The purpose of these tests was twofold. First, they would help in planning the amount of fluid and sand on any future job and, second, the optimum number of pumps to use. Table I summarizes the results of these tests and, also, the frac job data. No trouble occurred during the job and sand pump tests produced only a few gallons of sand from bottom.

Equipment: The well was equipped for pumping identical to the temporary well No. 2 described earlier with the exception of the pumping unit. It was mentioned previously that a beam unit was preferred over hydraulic, and also that a 48" slow stroke was desired. Since pumping loads and torque requirements are much less for a slim hole, the Alten people of Lancaster, Ohio, were approached and manufacture of a special unit, much less in price than conventional models, resulted. The unit structure and beam were from larger, standard models. The gear reducer was only 16000 in. lb. rating instead of the usual 40000 in. lbs., and revolved larger 25000 in. lb. cranks in order to obtain the longer stroke. A large horsehead was the only specially-constructed item necessary. The unit was designated by Alten as Model L-4-17-48. The price of this unit contributed greatly to the reduced overall cost of the project.

INJECTION RATE TESTS AND FRAC JOB DATA

SLIM HOLE PERMANENT COMPLETION - TEST WELL NO. 6

Injection Rate Tests

Conducted in 3256' of 2-1/2" casing

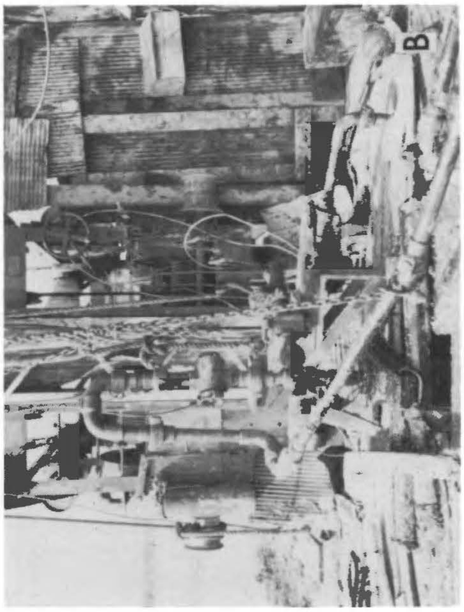
Pumps	Pressure	Bbls./Min.	Pressure Increase	Injection Rate Increase Bbls./Min.
1	1800	6.5		
2	2200	8.5	400	2
3	2800	11.0	600	2.5
4	3800	12.4	1000	1.4

Fracture Job Data

Type -	Viso Frac	
Pumps -	Four Halliburton T-10	
Pressures -	Initial 3500	Final 3400
Viso Frac -	500 Bbls. or 14,800 gals.	
Sand -	16,300 lbs. of 20 x 40 mesh	
Sand-Oil Ratio -	1.1 lbs./gal.	
Flush -	20 bbls.	

TABLE I

SLIM HOLE PERMANENT COMPLETION TEST WELL NO. 6



In order to obtain the flexibility of pumping speeds found in hydraulic units, an auxilliary four-speed industrial transmission manufactured by the Turner Uni-Drive Company of Kansas City, Missouri, was installed between engine and unit gear reducer.

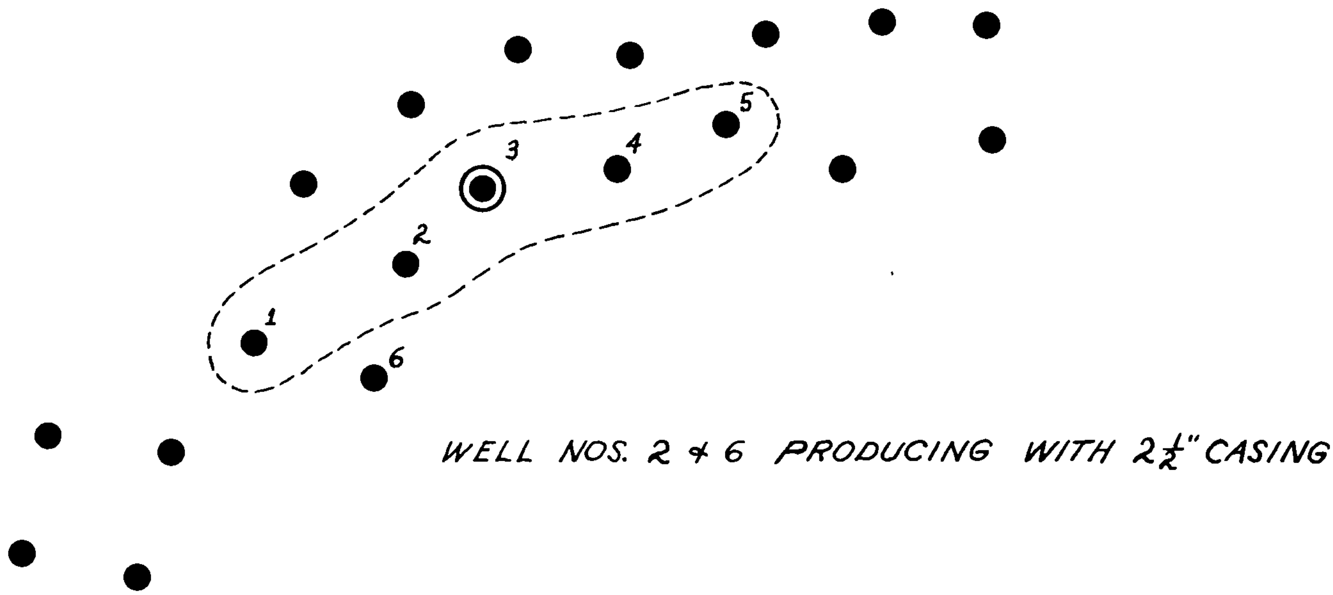
Operation and Maintenance History: It was previously mentioned that the natural production was not large, therefore, after fracture and installation of pumping equipment, the well's initial rate was about 80 barrels per week and, after two years' production, is making 30 barrels per week. It has been operated on an intermittent schedule at about eight or nine strokes per minute.

The pump and wire line performed very well during the first 1-1/2 years at which time the steel core began to show signs of failure. Externally, the line shows very little wear, however, when the 1/2" rods were recently removed from the No. 2 temporary well, the wire line was removed and replaced with these rods.

The one problem of greatest concern when initially contemplating operation of a Clinton slim hole was that of paraffin accumulations. Two preventative measures were taken. First, a beam-operated chemical injector was placed on the well and, second, a back pressure valve on the tubing to prevent unloading. To date there has been no serious trouble due to paraffin on either the No. 2 temporary or this permanent No. 6 well, shown in Figure 1.

MAP OF AREA

GAS RECYCLING PROJECT
COSHOCTON COUNTY OHIO



WELLS WITHIN DOTTED AREA HAVE RECEIVED MOST BENEFIT FROM GAS RECYCLING

TWO YEAR ESTIMATED GAIN

WELL NO.	GROSS BBLS
1	5000
2	8000
3	INJECTION WELL
4	7500
5	1500
	TOTAL 22,000 BBLS

FIGURE 1

Savings Due to Slim Hole Method: The main objective of any slim hole completion is to cut costs. Original estimates were that the Ohio producer could eventually reduce overall costs by as much as 15% to 20%. This still is a possibility. Natol saved or reduced its normal completion cost in this case by $3, 500, or about 12%. Although this is below the ultimate goal, it should be recognized that the first of any new projects or manufactured items is more costly. Further reductions will come with improved variations and new tools now available. Any future completions of this type by Natol will probably be set through and perforated or notched.

Future in Ohio: The development of slim hole methods and equipment is very much on the increase in a petroleum industry which is seeking to put less "iron" and fewer dollars in a hole. Ohio operators are very fortunate in that their tubular equipment has a very long service life. Casing may be run and pulled several times before it is unserviceable, however, as these materials are eventually used up, new must be purchased. During the last two or three years, we have seen a switch in purchasing from 5-1/2" casing to 4-1/2". This is just another step in the slim hole direction.

There are no insurmountable obstacles or lack of equipment to prevent the Ohio operator from moving into this type completion if and when the economic situation deems it advisable. Natol's experience has shown that any Clinton well can be completed and produced with 2-1/2" or 3" casing.

PART II THE GAS RECYCLING PROJECT

What are some of the reasons for attempting a gas recycling project? First of all, the history and records are encouraging. The "gas drive" or recycling method and other variations, such as "pressure restoration" and "pressure maintenance," have been employed extensively in the United States over the past 25 years. Many projects have and are operating in Ohio, most with a good degree of success. The prospect of increased ultimate recovery and more rapid pay out has certainly been the motive behind all attempts. Here in Ohio we talk of only 15% primary recovery by gas solution drive. This is reason enough to cause an operator to turn to any method which may help recover a few more percent of the oil in place.

Some First Considerations In Planning a Project.

There are several factors which the operator should consider when planning a recycling project. Some of these would be:

Control of the Area: Determine if your lease or leases cover the entire area of possible influence. If not, what are the prospects of offset development in the future which may affect your project adversely? If there is a possibility, consider unitization. In any event, it will be helpful to approach adjoining operators and all landowners, including your own, and discuss your plans and expected benefits in an effort to obtain their cooperation.

Records and History of the Area: One of the first considerations would be a study of present area development in regard to well spacing and the existing pattern which is important to the decision of converting or drilling of an injection well.

A study of all available drilling and electric logs, contour maps and sand information on the area should be made. This also will be necessary to the selection of injection wells. Further, the history of oil and gas production and decline curves are required.

Other records of importance are those of completion methods, casing programs and equipment of wells in the area of investigation.

Availability of Gas: The success of a gas recycling project requires ample supplies of natural gas; therefore, the earlier a project can be initiated on new leases, while flush gas is available and reservoir pressures are high, the greater are chances for an economic success. If the area is older and considerable gas has been removed from the lease, outside purchases and their cost may have to be considered.

The volume of gas required will normally increase as oil is displaced from the reservoir, however, if lease equipment is maintained in good condition with no leaks, all lease and purchased gas may be sold at abandonment with very little loss.

History and Development of Project Area.

There are probably very few Ohio Clinton leases which meet all of the ideal requirements for gas recycling. Natol's search resulted in the selection of three fully owned and operated leases in Monroe Township, Coshocton County. All wells were completed in the Clinton sand, the majority during 1956 and 1957. Depths were in the range of 3400' to 3500' and spacing averaged 15 to 18 acres per well.

All wells were cased and cemented with 5-1/2" to or through the sand except for the one permanent slim hole discussed earlier. Also, prior to recycling, one well had been converted to the temporary slim hole packer installation.

Fracture jobs on all wells were Vis-O-Frac 500-barrel treatments with 20,000 pounds of 20 x 40 mesh sand.

Selection and Preparation of Injection Well.

The selection and preparation of an injection well involves consideration of factors such as location in the pattern of existing wells, relation to any known subsurface structure or contours, lithologic properties of the sand and completion and casing programs followed. Attention to these factors will help prevent future loss of production to offset operators, increase efficiency of the project and also determine the use of packers for zone control providing two or more exist in the reservoir.

Attention to these factors was given in the selection of Natol's injection well which, prior to conversion, had produced 14,000 gross barrels in the one and a half years on production.

All pumping equipment, tanks, trap, unit, etc., were retired from the well, the value of which was one-half of the original total equipment value.

The well was then cleaned out and well head equipment installed. Injection was to be down the 5-1/2" casing since tubing had been removed.

Selection and Hookup of Equipment.

The main items of equipment in the injection system were a two-stage compressor, homemade cooler and a glycol dehydrator.

Compressor: The Chicago Pneumatic compressor used was originally a 5 x 11" single stage, which was converted for this project to a two stage by purchasing a 6 x 11" cylinder assembly and a sleeve kit to convert the 5 x 11" to a 3-3/8 x 11" cylinder. The capacity at 800 pounds discharge is from 300 to 500 Mcf/day at inlet pressures of 30 to 90 pounds, respectively. It is believed that 800-pound discharge pressure rating is ample for any Clinton project since other current projects are operating in the range of 600 to 700 pounds.

Cooler: Gas temperature at discharge from the compressor is high, and in order to aid dehydration, a cooler was made from 24 pieces of 1" x 20' pipe. This cooler drops the gas temperature about 75^{o} to 80^{o} before it enters the glycol dehydrator.

Glycol Dehydrator: On other projects, operators have experienced considerable difficulty with freezing of the injection well due to hydrate formation. Solvent injection has been used with some success but can become expensive. The best solution has been the installation of a glycol dehydrator. The dehydrator for this project is a Parkersburg Rig and Reel skid-mounted package unit, and being the smallest unit available, has a capacity of 890 Mcf at 800 pounds and 1,000 Mcf at 1000 pounds working pressure.

Other Equipment: Other equipment required in the injection system includes back pressure and suction regulators, drip, meter, check and relief valves, line scrubber and other valves and fittings. The position of these and other equipment in the injection system is shown in Diagram III.

Performance and Maintenance of Equipment.

In two years, very little trouble has been encountered with equipment operation. The compressor is being operated well below capacity and regular inspections and oil changes have kept down-time to a minimum The dehydrator has given no trouble of any kind and removes about two barrels of fluid per week.

The back pressure valve has been set to keep field pressure at an average of 60 to 70 pounds.

Performance and Maintenance of Injection Well.

Gas was started into the injection well about January 1, 1959 at an initial pressure of 320 pounds and rose steadily to 550 pounds in about 12 weeks. It then climbed slowly to nearly 600 pounds during the next 15 weeks and fluctuated between 550 pounds and 600 pounds for the next six months. At this point, the injection pressure began a steady decline which has just recently begun to level due to additional gas being hooked into the system. The decline in pressure is assumed to be the result of decreased resistance to flow of gas as oil is displaced from the formation and, also, that the cumulative recycled volume is shown to be increasing at a decreasing rate when plotted on semilog paper.

RECYCLING EQUIPMENT

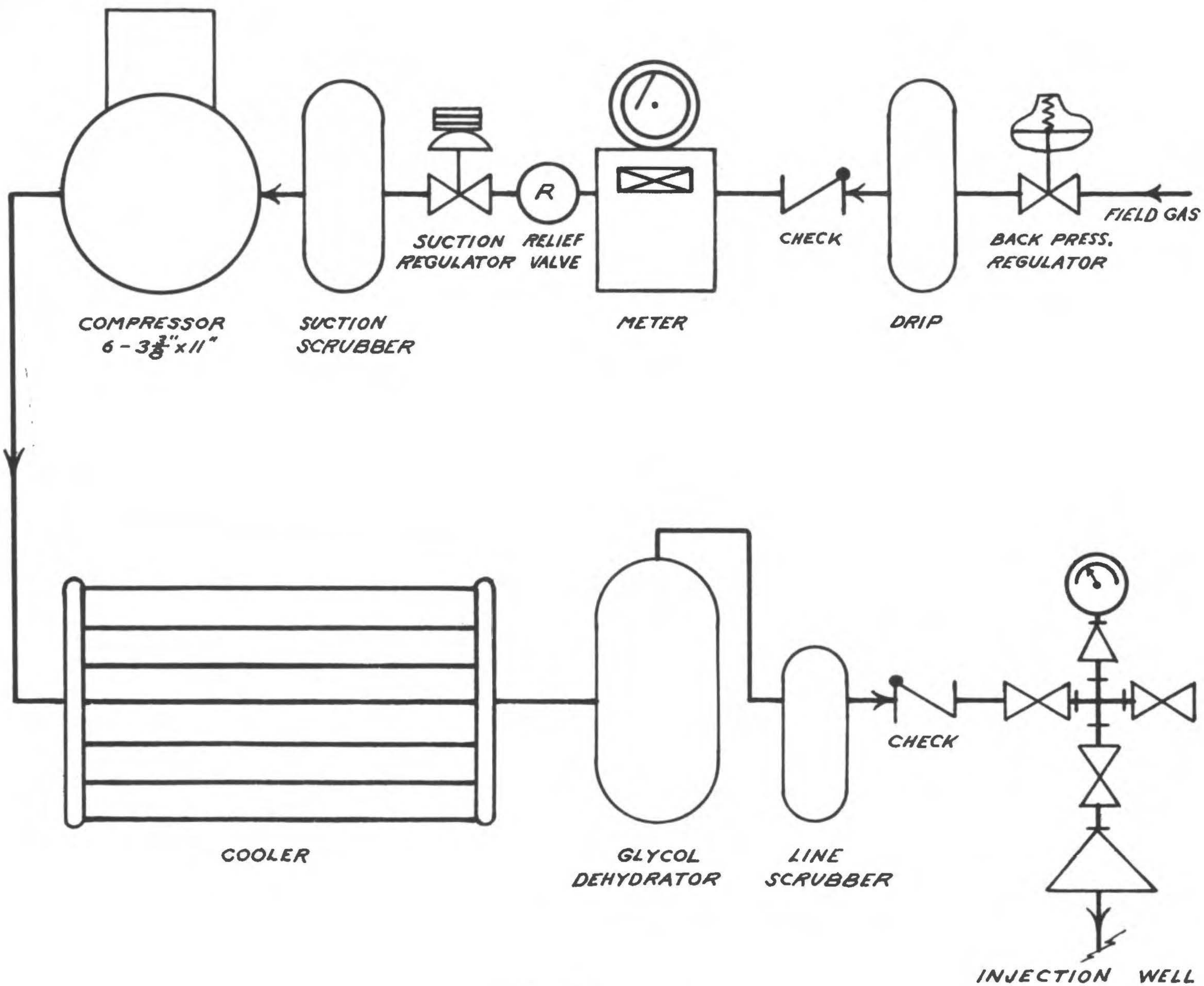


DIAGRAM III

RECYCLING EQUIPMENT DIAGRAM

COMPRESSOR AND COOLER

Since injection began, the well has never required service or given any trouble. Freezing has never occurred and no reverse flow or other treatment has been necessary. Graph I shows injection well pressures.

Gas Recycling Data.

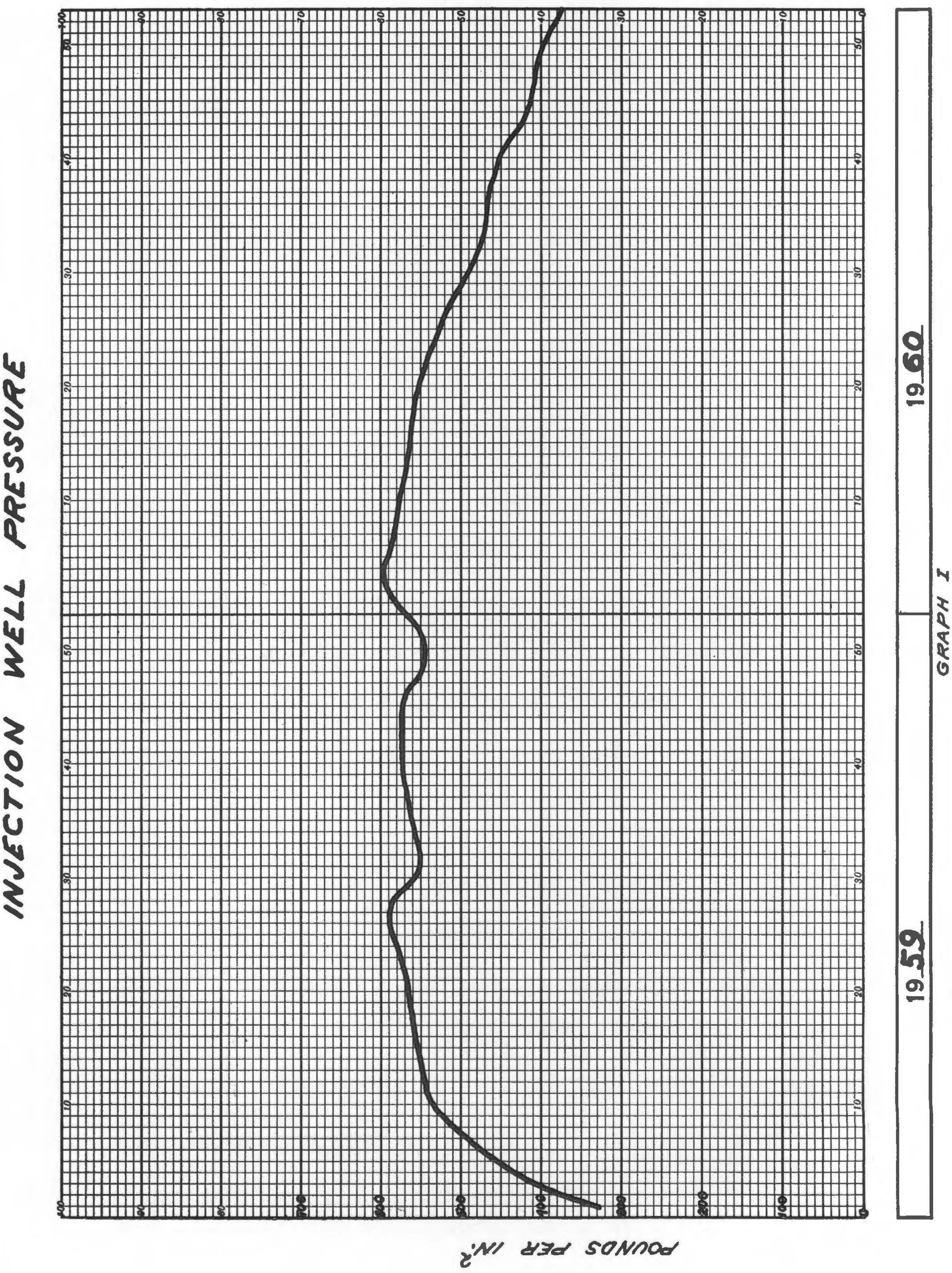
It was mentioned previously that the injection well was one and a half years old when injection began around January 1, 1959. Since that time about 125 MMcf has been injected at a daily average rate of 168 Mcf/day.

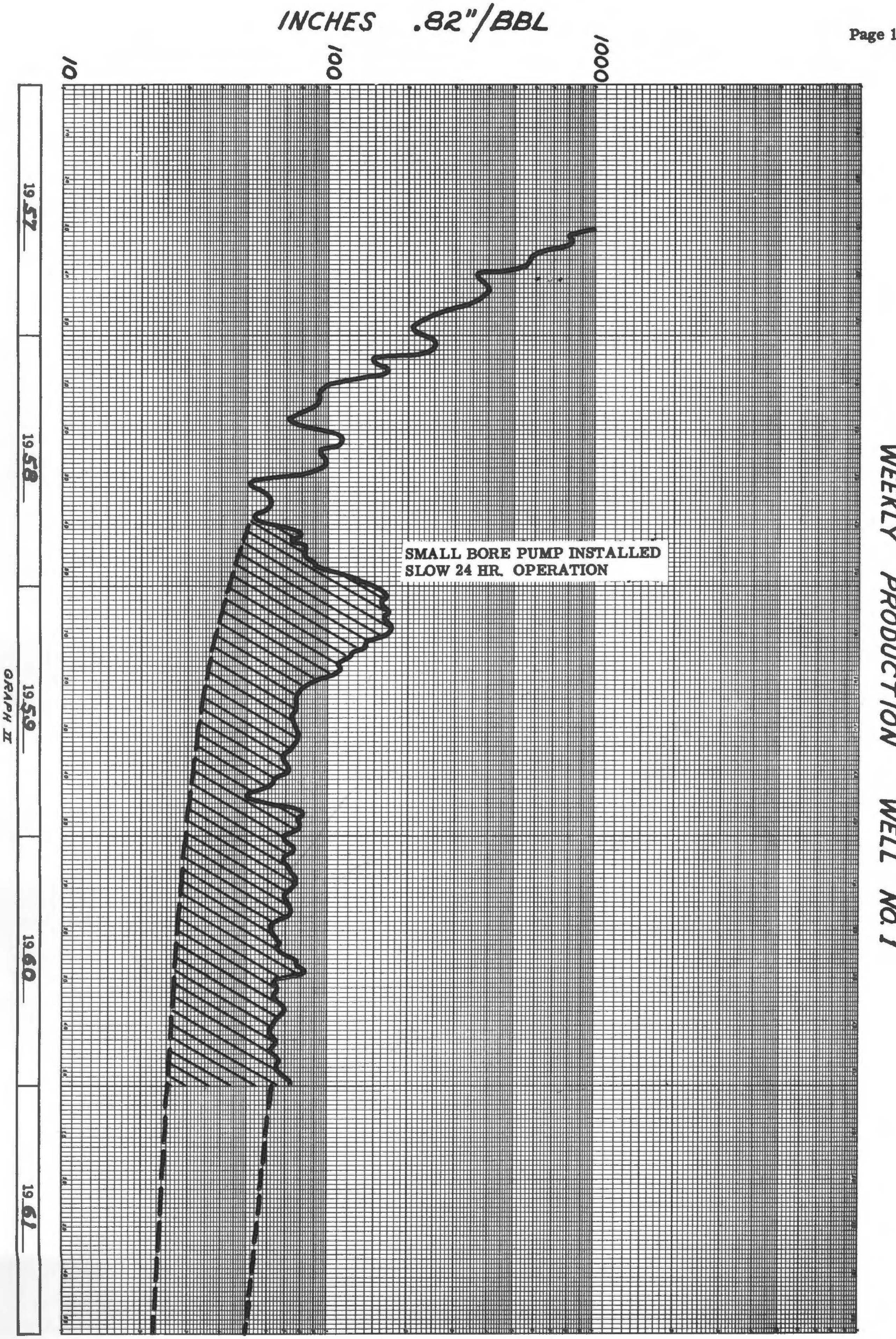
The question of a rapid or gradual initial injection rate and pressure build-up comes to mind when starting a project. According to the literature, it is preferable to build these factors at a slow rate. It is believed that a body of gas will accumulate around the injection well and create a liquid seal or solid bank of oil between the moving gas and the recovery wells. If pressure is built too rapidly, the liquid seal may be penetrated and channelling occur thereby reducing the efficiency of the drive.

Effect of Recycling on Production.

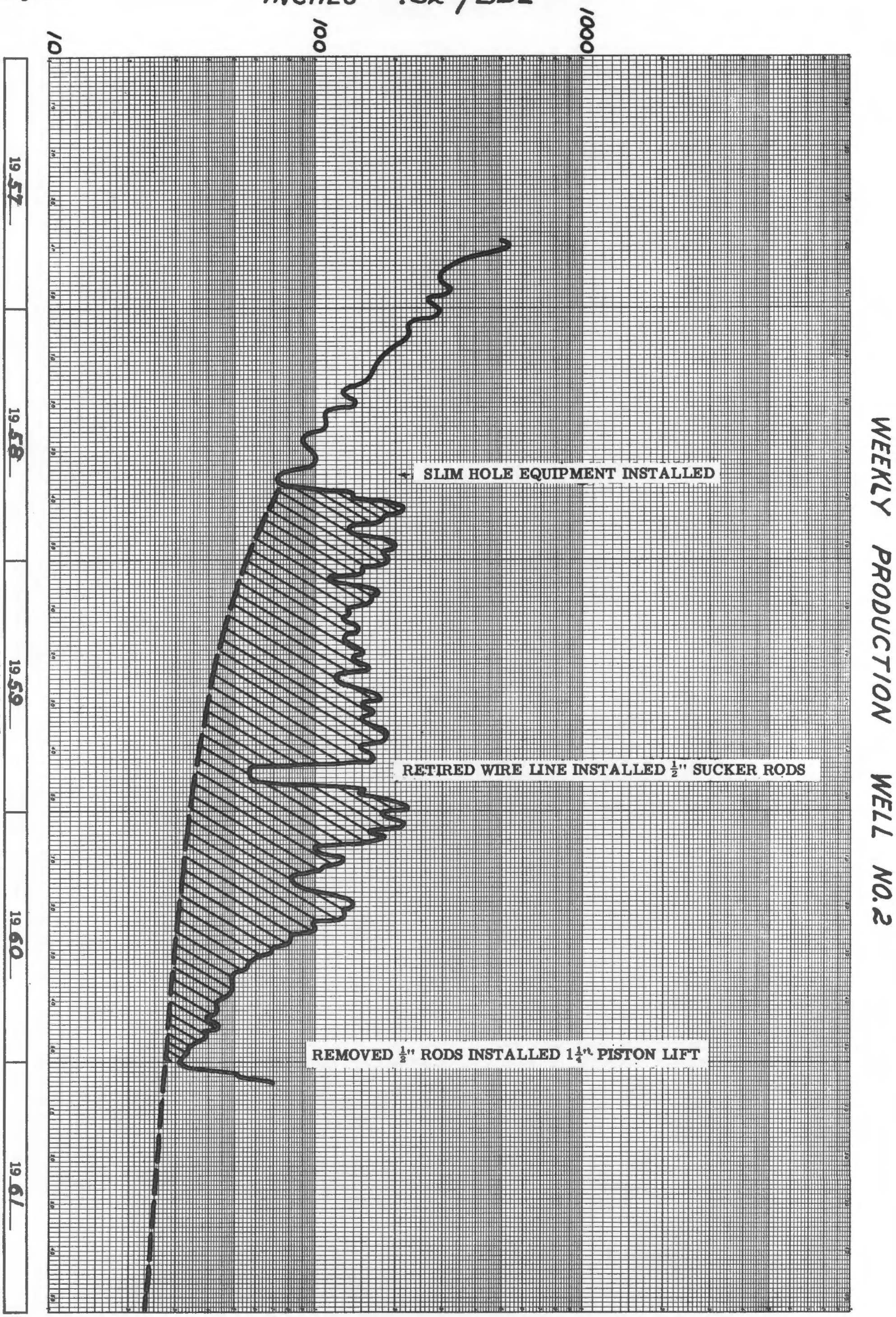
The effect of gas recycling has become evident in the production curves of several wells, however, four have received most of the benefit and only these will be discussed in detail.

Reference to Figure I will show the injection well and the four wells just mentioned. Also shown is the estimated two-year gain as a result of recycling.

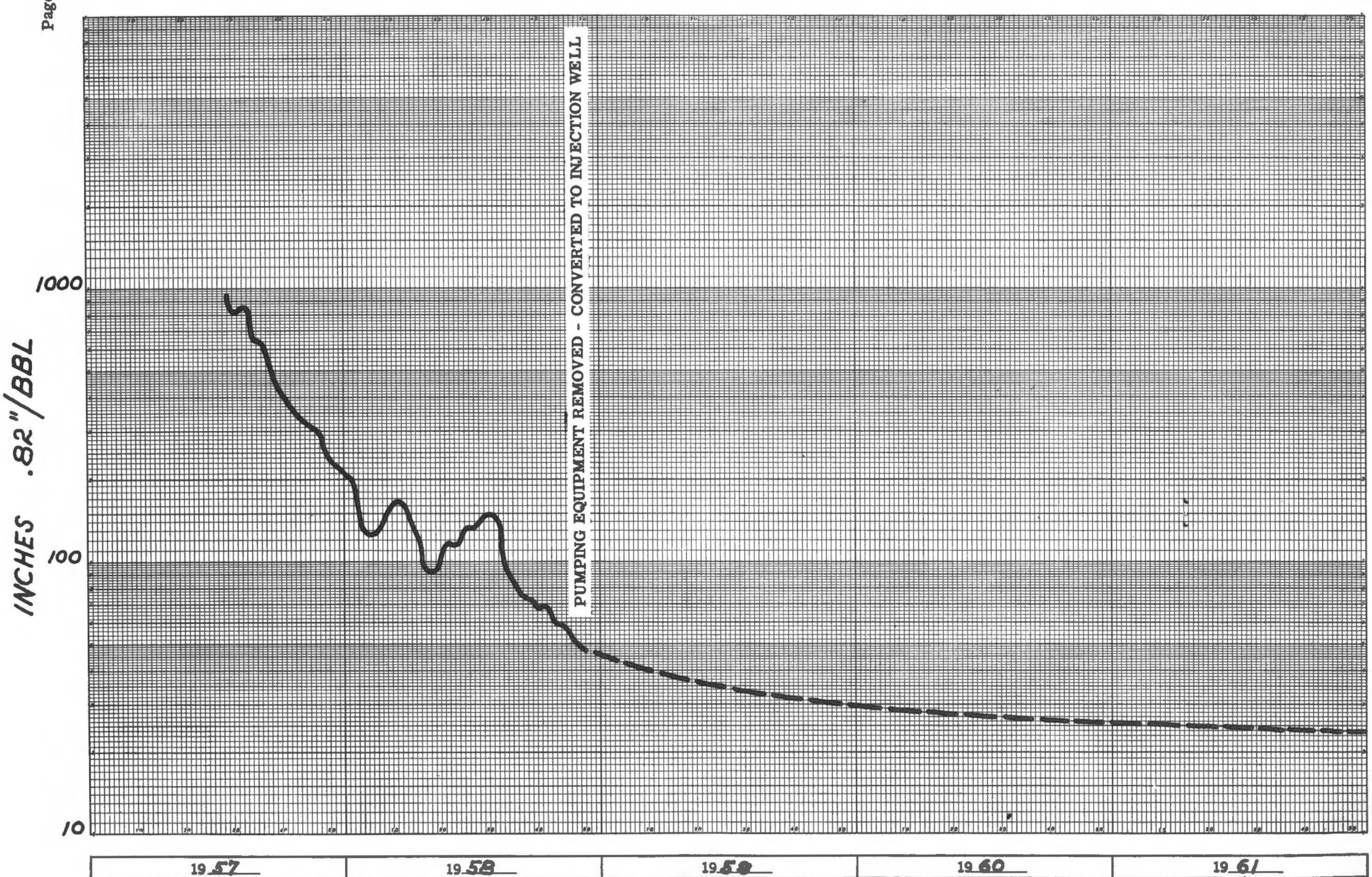

INJECTION WELL PRESSURE
POUNDS PER IN.²
19 59
19 60
GRAPH I



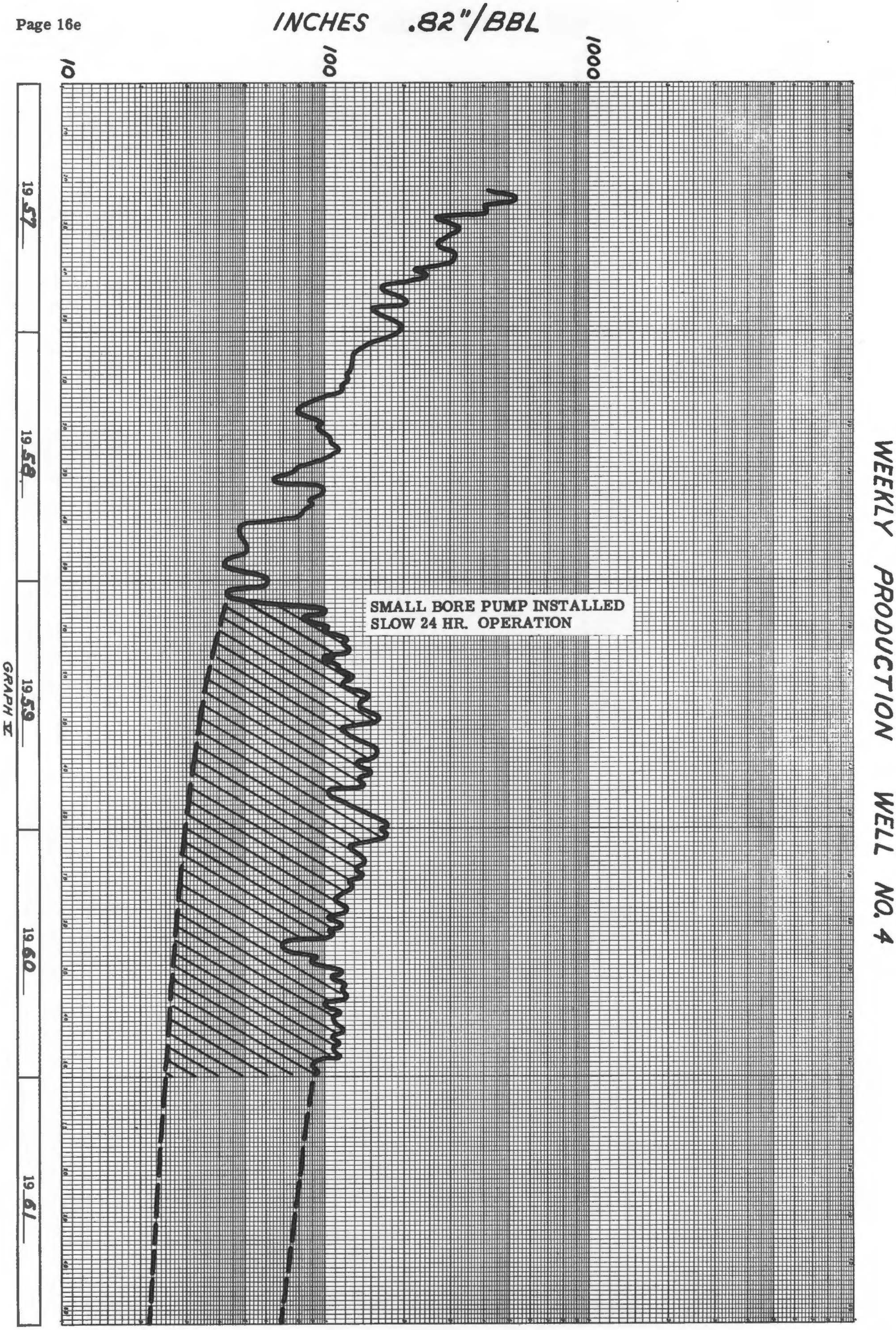
INCHES .82"/BBL
10
100
1000
19 57
19 58
19 59
19 60
19 61
SMALL BORE PUMP INSTALLED
SLOW 24 HR. OPERATION
WEEKLY PRODUCTION WELL NO. 1
GRAPH II

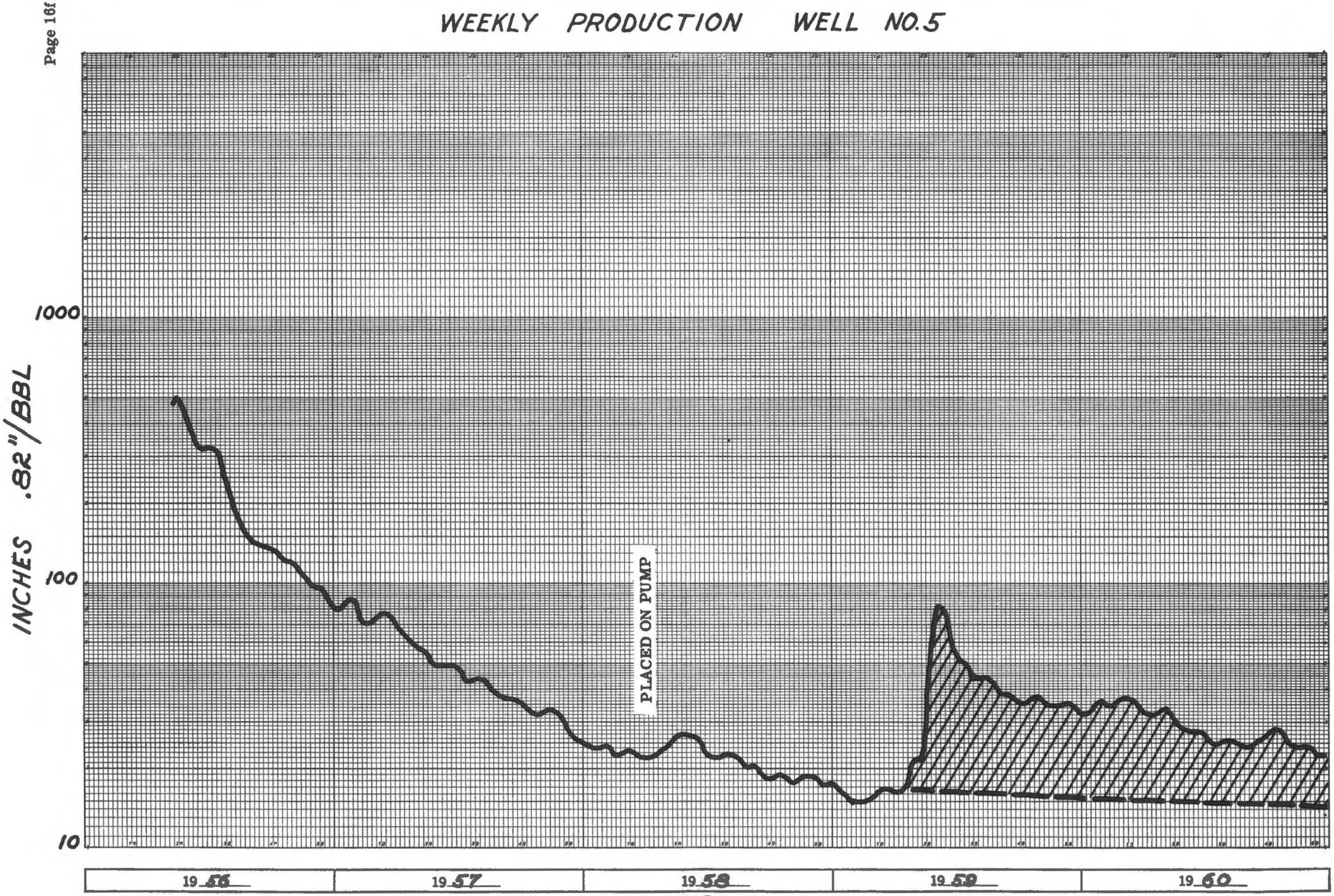

INCHES .82"/BBL
10
100
1000
19 57
19 58
19 59
19 60
19 61
GRAPH III
WEEKLY PRODUCTION WELL NO.2
SLIM HOLE EQUIPMENT INSTALLED
RETIRED WIRE LINE INSTALLED ½" SUCKER RODS
REMOVED ½" RODS INSTALLED 1¼" PISTON LIFT

WEEKLY PRODUCTION WELL NO.3



GRAPH IV


INCHES .82"/BBL
10
100
1000
WEEKLY PRODUCTION WELL NO. 4
SMALL BORE PUMP INSTALLED
SLOW 24 HR. OPERATION
19 57
19 58
19 59
19 60
19 61
GRAPH V



WEEKLY PRODUCTION WELL NO.5
INCHES .82"/BBL
1000
100
10
PLACED ON PUMP
19 56
19 57
19 58
19 59
19 60

GRAPH VI

Graphs II through VI show the production curves of these four wells and, also, the injection well. It should be mentioned that some of the initial increased production rates were due to a change in production operations and equipment. Small, one inch bore pumps were installed, back pressures decreased and the wells placed on 24-hour, very slow operation in order to continually handle the production increases due to recycling and also maintain a continuous seven-day gas supply to the compressor.

<u>Economics - Present and Future.</u>

Total initial cost of the project plus two years' operating expenses is $38, 200. The estimated two-year gross increase from production is $52, 360. These costs and estimates are shown in Table II.

The future life of the project may be another three to five years and will require changes in operation such as selection of other injection wells and application of differential pressure control in the reservoir.

An estimated additional $50, 000 after operating costs, due to recycling, may be realized during the life of the project. Also, several thousand dollars worth of equipment will be salvaged at abandonment and sale of gas will also begin at that time. However, before recycling is actually abandoned, consideration will be given to the possibility of other methods of secondary recovery, mainly to water flooding.

RECYCLING ECONOMIC STATUS

TWO-YEAR ESTIMATE

Equipment Expenditures

		Investment
Injection Well		
Original Equipment	$13,800	
Retired Equipment	7,100	
		$ 6,700
Injection Equipment		
Compressor	$21,000	
Dehydrator	3,800	
Cooler and Other	1,700	
		26,500
Total Investment		$33,200
Operating Expenses		5,000
Investment and Operating Costs		$38,200

Estimated Production Gain

Well No.	Gross Barrels	Net Value @ $2.72/Bbl.
1	5,000	$11,900
2	8,000	19,040
3 Injection Well		
4	7,500	17,850
5	1,500	3,570
Total	22,000	$52,360

TABLE II

Recycling Summary.

It is believed that the successful application of gas recycling to many Ohio Clinton leases can be accomplished if careful planning and consideration is first given to a study of the factors mentioned earlier. These were: a study of all available history and records, control of the area by unitization if necessary, availability of ample gas and proper selection and operation of injection wells and equipment.

In some areas where existing well patterns do not provide a desirably located injection well, an operator may find it advisable to drill one, in which case, if the area is new, flush production may be produced to help pay out and then convert to injection.

It is important that gas recycling be initiated as early as possible in the development of an area before lease gas is sold and while reservoir pressures are high.

GENERAL CONCLUSION

Two suggestions have been presented in this paper which are considered to be important and increasingly necessary to both current and future oil operations in Ohio. These suggestions were:

I That each operator review and study his current properties and plan his future developments with gas recycling in mind.

II That we should analyze and plan for the future with an awareness of the availability of methods and equipment to complete and produce Clinton and other formations with less cost, in smaller strings of casing, with smaller tubing, rods, pumps and pumping units.

The history, equipment and technical developments behind these suggestions are not new or unavailable. Recycling has been in practice for many years in practically every oil producing state, including Ohio as one of the first. Further, scores of slim hole and multiple completions are being recorded every year all the way from Canada down to our most southern oil producing states.

Natol's initial experiences in these areas are encouraging, and it is hoped that other projects and experiences will be forthcoming in the near future from other operators in our Ohio industry. It is further hoped that by sharing these experiences through technical organizations and our own Oil and Gas Association, that the future of the oil industry in Ohio will be more firmly assured in the years which lie ahead.

ARE CLINTON SAND FLOODS ECONOMICALLY FEASIBLE ?

By H. C. Slider

ARE CLINTON SAND FLOODS ECONOMICALLY FEASIBLE ?

ACKNOWLEDGEMENT

Most of the data and many of the conclusions cited herein were taken from an M. Sc. degree thesis "A Preliminary Investigation of the Susceptibility of the Clinton Sand of Ohio to Water Flooding," by Mr. Howard E. Henney. This preliminary study was made in 1959 and 1960 at the Ohio State University under the direction of the author. Mr. Henney and the author are both grateful to the many oil producers and service companies who contributed information and time to this study. The investigation will be continued as suitable graduate students and necessary funds become available.

SUMMARY

Based on very meager Clinton-sand core analysis and laboratory displacement tests, and the application of general reservoir engineering principles, it is tentatively concluded that effective injection of water into a primary depleted Clinton reservoir should recover flood oil equal to between 60 and 195 per cent of the primary production, depending upon the porosity, connate water saturation, sweep efficiency, and primary recovery (low primary gives high percentage flood recovery).

Initial pools to be flooded should be chosen where well completions are such that injection can be restricted to the oil-bearing portions of the reservoir.

Extensive core analysis, laboratory displacement and possibly PVT analysis work should be done to validate these tentative conclusions.

INTRODUCTION

For several years the Clinton sand has been the leading oil producer in the State of Ohio[1]. Oil production from the Clinton sand extends from Cuyahoga County on Lake Erie south to the Ohio River. The Clinton-sand producing area is about 50 miles wide. The principal Clinton oil fields lie in the central portion of this belt from Wayne County in the north to Hocking County in the south, as indicated in Figure 1.

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1. Ohio Division of Geological Survey, Report of Investigations, No. 32, 1956; No. 35, 1957; No. 37, 1958; No. 39, 1959.

Figure 1. - Oil and Gas Fields of Ohio.

Since accurate data on the Clinton sand are not generally available, there is room for considerable conjecture concerning the exact nature of the sand body. However, it is apparent that there is present considerable interbedded shale. It also appears that the clean sand is lenticular. It has been estimated that the sand thickness averages 22 feet[2].

The Clinton sand produces oil, practically without exception, by the solution gas drive mechanism. It has been estimated, based on meager production data, that cumulative oil production from the Clinton totals about 100 million barrels.

There are three main areas of consideration to determine the feasibility of water flooding:

(1) Is there a sufficient quantity of oil in the reservoir after primary depletion.

(2) Can a sufficient quantity of the oil be displaced by injected water.

(3) Can a sufficient quantity of water be effectively injected into the formation.

OIL SATURATION AFTER PRIMARY DEPLETION

The attitude often prevails that secondary recovery is unfeasible because primary production has been marginal. It is true that primary recovery tends to indicate the total quantity of oil originally in place in the reservoir, and in this way it tends to indicate the secondary recovery potential. However, it also is proportional to the amount of natural energy in the reservoir (i. e. pressure, gas in solution, etc.), and secondary recovery potential is inversely proportional to the amount of natural energy, since the higher the natural energy, the lower will be the resulting oil saturation after flooding. Another way of saying this is that for a given oil reservoir the lower the primary recovery, the higher will be the oil saturation after primary recovery and consequently the higher may be the secondary recovery.

The ideal way of estimating oil saturation after primary recovery is through a volumetric study embracing geologic, core analysis, and PVT data. Specifically, we must be able to evaluate the reservoir volume drained by the subject well or wells, the average porosity, the original oil and/or water saturation, the original oil shrinkage factor or oil formation volume factor, the cumulative stock tank barrels of oil production, and the oil shrinkage factor or oil formation volume factor at the reservoir pressure prevailing when the flood is initiated.

Any one of these items is difficult to evaluate in the Clinton sand, but it is necessary to evaluate all items for a particular reservoir in order to reach any conclusions for a particular case. Since all of these items could not be evaluated for any reservoirs, it was necessary to take a more general approach.

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2. J. R. Lockett, "Introduction to the Petroleum Geology of the Clinton Sand of Ohio," Appalachian Geological Society Bulletin, Vol. 1 (Charleston: Charleston Printing Company, 1949).

Figure 2. - Location of Wells Covered by Core Analysis.

Per Cent Primary Recovery

Many studies have been made of primary recoveries from solution gas drive reservoirs. In all cases the investigators have concluded that such reservoirs rarely recover more than 25 per cent of the oil in place, and these recoveries may be less than 15 percent[3]. Without detailed volumetric study we cannot tell where the Clinton sand recovery falls in this range. However, since the Clinton has very low porosities and permeabilities it would appear that its primary recovery would fall in the lower range.

To reduce these percentage values to barrels, it is necessary to know the reservoir porosity and connate water.

Porosity

Very few data are available on Clinton production since the production is seldom prolific enough to warrant the cost of coring and core analysis. By contacting the various principal producers in Ohio, it was possible to obtain core analyses for only eight Clinton wells. In addition, two companies permitted us to analyze Clinton cores from wells which were practically dry holes. A summary of the results of these core analyses are shown in Table I, and the geographical distribution of the cores is shown in Figure 2. Cores A through H were analyzed in commercial laboratories, while cores 1 and 2 were the cores analyzed in the Ohio State University reservoir engineering lab. The sample-to-sample variation of porosity is also of interest and is indicated in Tables II and III for the "dry hole" cores analyzed at the Ohio State University. Saturations were not run on these samples since the cores had been exposed to the atmosphere for long periods before analysis.

The range of Clinton porosities indicated by core analysis was further verified by a study of gamma ray-neutron logs. Radioactivity log interpretation of the Clinton sand is complicated by the presence of the many interbedded shale stringers in the Clinton sand body. The technique used was to employ the gamma ray curve to indicate clean sand content and to correct the indicated neutron curve porosity on this basis.

Data was available on only one well having both core analysis and a radioactivity log. The comparison between core analysis and log calculated porosities for this well is shown in Figure 3. These limited data indicate considerable promise for this method of evaluating Clinton sand porosities. An excellent correlation between core analysis and radioactivity log calculated porosity is indicated. It presently appears that a sonic log also offers excellent possibilities for porosity evaluations.

Based on the data presented it appears that commercial Clinton sand production is obtained from sands with porosities averaging 9 to 15 per cent.

Connate Water

If the range of porosities and fractional saturation after primary depletion is known, an estimate of oil in place after primary will be possible if the connate water can be estimated. It is well known that core-analysis water saturations do not accurately indicate true formation water saturations, due to drilling fluid con-

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3. R. C. Craze and S. E. Buckley, "A Factual Analysis of the Effect of Well Spacing on Oil Recovery," API Drilling and Production Practice, 1945.

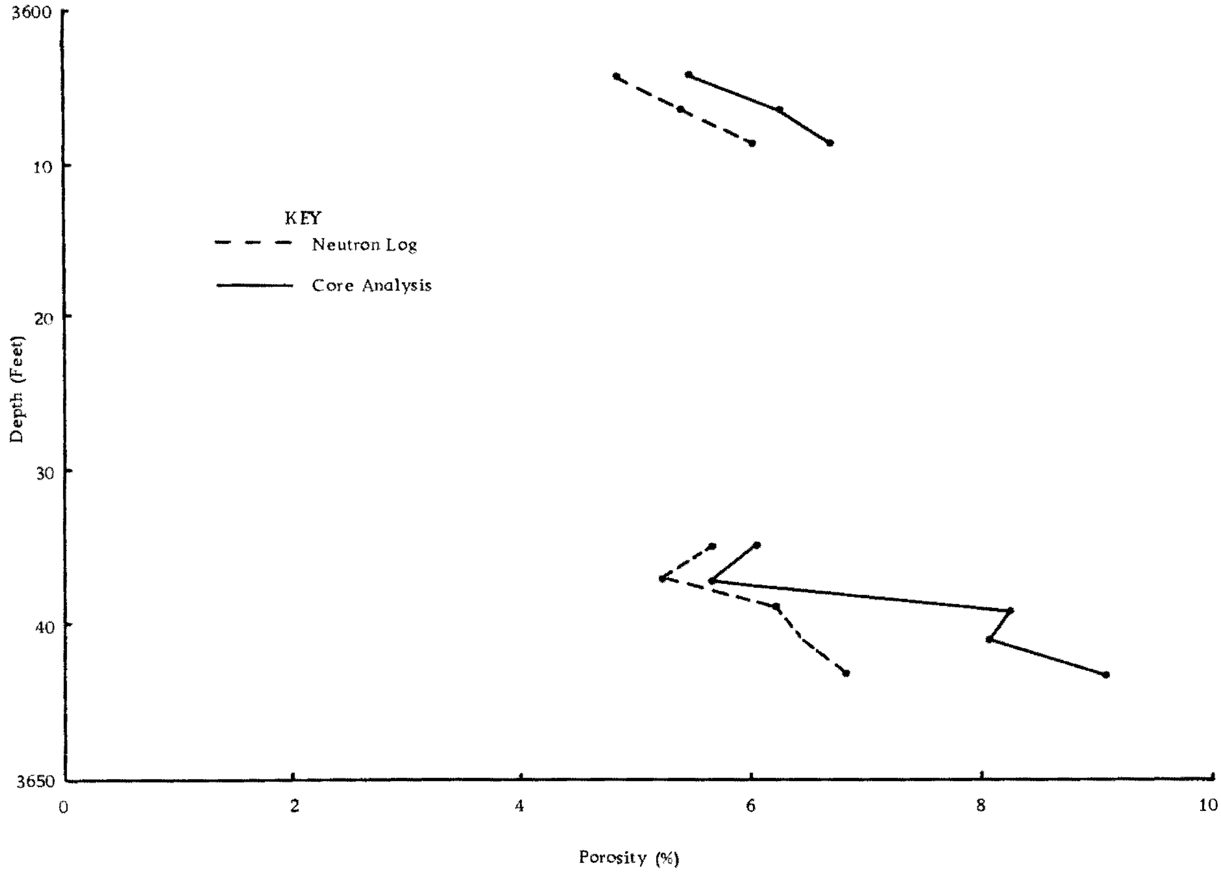

Figure 3. - Comparison of porosities.

tamination, which tends to make the water saturations high when the drilling fluid is water or of a water base. On the other hand, excessive evaporation due to improper handling or air drilling may tend to make water saturations too low. Since most cores are currently cut with water in the hole and are canned or frozen after recovery from the well, we would expect the water saturations from core analysis to be high. On this basis the connate water saturation would probably not exceed 27 or 28 per cent, which is in the range that would be expected for a tight sand such as the Clinton if it is preferentially water wet.

It will be noted from Table IV that laboratory resaturation of some Clinton samples indicated a connate water saturation of only about 16 per cent. It seems possible that this is due to an inability to completely saturate the effective pore volume with water, due to gas trapping (incomplete evacuation). This is evidenced by the rather large spread between the effective and total porosities of these samples. However, since there is a possibility that the Clinton is sometimes oil wet and Table IV shows some lower water saturations, 16 per cent will be used as the lower limit of the connate water saturation.

Oil Saturation After Primary Depletion

Based on the above estimated ranges of porosity, connate water, and oil saturation after primary depletion, we can estimate the range of oil saturations after primary depletion in barrels per net acre foot of sand as follows:

Assumptions:

(1)	Primary Recovery	15	25
(2)	Porosity	9	15
(3)	Water Saturation	28	16
(4)	Pore Volume (Bbls/A. F.)		
	(2) x 7758	698	1164
(5)	Connate Water (Bbls/A. F.)		
	(3) x (4)	195	186
(6)	Original Oil Saturation (Reservoir Bbls/A. F.)		
	(4) - (5)	503	978
(7)	Oil Saturation After Primary (Reservoir Bbls/A. F.)		
	1. 00 - (1) x (6)	428	733
(8)	Primary Oil Recovery (Reservoir Bbls/A. F.)		
	(6) - (7)	75	245

The highest connate water and lowest primary recovery were grouped with the lowest porosity since this is the characteristic trend of reservoir data. Based on the noted assumptions the primary oil recovery will range between 75 and 195 barrels per acre foot. Since Clinton Sand reservoir pressures are relatively low, no correction is made for oil shrinkage. This should introduce an error of less than three per cent.

DISPLACEMENT EFFICIENCY

Linear Laboratory Displacements

In an effort to evaluate the amount of fluid which might be displaced from the Clinton sand by water, laboratory linear displacement tests were attempted on five three-quarter-inch diameter Clinton sand plugs. The plugs used were taken from the best sections of core #1 for which other core analysis data is shown in Table II. The procedure used is fairly standard. The plugs were cleaned by retorting with solvent and drying; all the air was removed from the samples with a vacuum pump; they were saturated with water; the water saturation was reduced to a simulated connate water by displacing all water possible with oil; and the residual oil saturation after flooding was evaluated by displacing all the oil possible with water. End effects were minimized by keeping the downstream end of the sample covered with fluid and using a relatively high displacement pressure drop.

Data concerning the displacement tests are indicated in Table IV. A comparison of the porosities for core #1 samples as shown in Tables II and IV, indicate that the displacement test samples had an average effective porosity of 10. 3 per cent, while the conventional core analysis porosities had an average of 8. 21 for the permeable section. This is undoubtedly due to choosing the most permeable samples for the displacement tests. The difference is probably even greater since, as noted previously, it appears that the displacement samples were not completely saturated with water; and this was the basis for the porosity calculations.

Note that results from two of the samples are not included in the data averages. Sample #2 became plugged after being saturated with water (This will be discussed later). Part of sample #3 was chipped and lost in removing it from the displacement apparatus, which made the accuracy of this data doubtful. Nevertheless, the close agreement of the data from the other three samples lends some confidence to the results as applied to this particular core. The average residual oil saturation after water displacement is 38.7 per cent. Since the effective porosity measurements may be in error, we can best use this figure by comparing it with the original hydrocarbon porosity represented as the oil saturation at the start of the displacement, 83.9 per cent. In this manner we may deduce that the residual oil saturation after flooding is $\frac{38.7}{83.9} = .46$ or 46 per cent of the original hydrocarbon saturation.

Flood Recovery with 100 Per Cent Sweep

Using the previously estimated ranges of original oil saturation and primary oil recovery, the residual flood recovery after a 100 per cent water sweep can be estimated.

Assumptions:

Primary Recovery (%)	15	25
Porosity (%)	9	15
Water Saturation (%)	28	16
(9) Residual Oil after 100% Sweep (Bbls/A. F.) (6) x .46	231	450
(10) Flood Recovery after 100% Sweep (Bbls/A. F.) (6) - (8) - (9)	197	283
(11) Flood Recovery after 100% Sweep (% of Primary Recovery) (10)/(8)	263	116

Of course the actual recovery will depend upon the sweep efficiency which results from the injected water. Also note that the lab displacement data did not cover a wide enough range of porosities to predict the variation in residual oil with porosity.

Sweep Efficiencies

It is difficult to generalize concerning sweep efficiencies characteristic of a particular reservoir since these efficiencies depend on the microscopic reservoir qualities as well as the geometry of the particular reservoir. However, at least two general observations can be made concerning Clinton sand sweep efficiencies.

The Clinton sand is characteristically a low permeability reservoir, and the permeability distribution of low permeability reservoirs is not generally as adverse as the permeability distribution of highly permeable reservoirs. Secondly, the Clinton reservoirs are invariably limited by shale outs or impermeable sand; thus water injected into the oil bearing sand will not tend to be lost outside the productive reservoir, and the oil bank cannot be pushed outside the productive reservoir.

Balancing these factors is the lenticular nature of the Clinton sand, which will tend to limit the reservoir continuity between the imputs and the producers.

Considering all of these factors it appears that sweep efficiencies in the Clinton should be no worse than those of proven water flood reservoirs. Thus, overall sweep efficiencies in the Clinton should fall in a range of 50 to 75 per cent.

Estimated Flood Recovery

Flood recovery can then be estimated as follows:

Assumptions:

Primary Recovery (%)	15	25
Porosity (%)	9	15
Water Saturation (%)	28	16
Residual Oil (%)	46	46
Recovery at 50% Sweep Efficiency (% of Primary Recovery)		
(11) x .5	131	58
Recovery at 75% Sweep Efficiency (% of Primary Recovery)		
(11) x .75	197	87

Thus, based on the estimated reservoir parameter ranges and a residual oil of 46 per cent, flood recovery should very between about 60 per cent and 195 per cent of the primary recovery, depending upon the actual reservoir qualities of the particular reservoir.

EFFECTIVE INJECTION CAPACITY

Obviously no water flood recovery can be achieved if water cannot be effectively injected into the oil bearing sands. Many producers quickly jump to the conclusion that the Clinton sand is too tight for economical water injection. However, if properly conditioned injection water can be delivered to the sand face in the well, that well should permit injection at a rate comparable to the initial oil production rate, since the viscosity of the injection water should be comparable to the viscosity of the original reservoir oil. This conclusion can be reached by considering that the viscosity is the only flow parameter which is different, except for the pressure gradient, which can probably be maintained on injection at a value comparable to the initial production pressure gradient.

Only one or two floods have been tried in the Clinton as far as the writer has been able to ascertain. These have been on one or two injection well pilots which lacked the pressure back up necessary to force oil into the low capacity producers. However, these pilots do provide us with some injection data. In Figure 4 is shown part of a Clinton injection well history. The rates and pressures varied with mechanical difficulties and formation fill up, but it is significant that the well took water at well over 100 BPD for extended periods without excessive surface pressure. The sand face pressures for this well were between 1800 and 2000 psia.

Possibly the biggest difficulty in successfully flooding the Clinton will be the difficulty of delivering well conditioned clean water to the oil-sand face. This problem is made difficult by typical open hole completions which have large sections of shale, gas stringers, and oil sands exposed in the open hole. Adaptation of such wells for flood use, particularly as injection wells, presents many problems. However, the improvement in Clinton-sand well completion techniques in recent years makes it possible to flood many recently developed reservoirs using the present existing wells. Economical means of adapting the problem wells can probably be devised in the future. Injection-well experience indicates that it may not be necessary to exclude the shale section from the open hole and it may be possible to preferentially plug the exposed gas stringers.

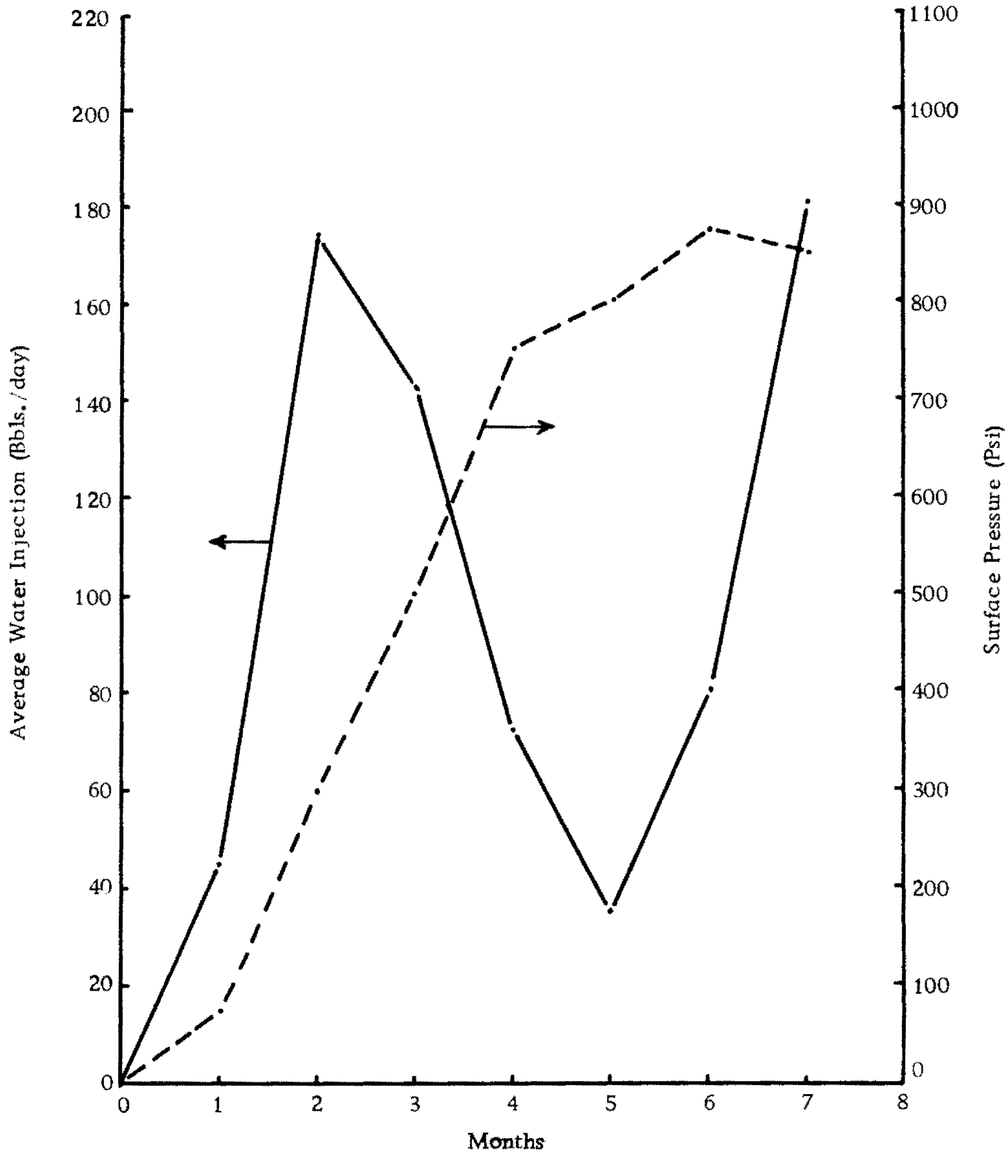

Figure 4. - Clinton Sand Pilot Flood Injection History - Well #1.

Injection difficulties were experienced in the laboratory displacement tests. Core sample #2 became so effectively plugged that the displacement test could not be continued (See Table IV).

TABLE I
Clinton Core Analyses
(Average Values of Most Permeable Zones)

Analysis	Effective Porosity (%)	Permeability (Millidarcys)	Residual Saturation Oil (%)	Water (%)
A	9.9	6.7	22.0	26.4
B	9.6	12.0	19.4	19.0
C	9.3	6.2	24.6	19.6
D	6.0	0.1	23.6	27.6
E	8.8	0.0	22.2	27.7
F	7.9	1.1	20.9	24.0
G	10.1	0.4	24.2	14.7
H	15.1	45.0	39.6	28.1
1	8.0	0.0	....	....
2	8.2	1.2	....	....

TABLE II
Core Analysis - Core #2

Sample Number	Effective Porosity (%)	Total Porosity (%)	Permeability (Millidarcys)
1	5.03	3.9	0
2	6.02	3.8	0
3	5.66	7.4	0
4	5.77	6.5	0
5	6.38	6.25	0
6	6.23	5.8	.232
7	5.41	5.5	0
8	6.25	7.4	0
9	5.92	5.75	0
10	6.66	6.3	0
11	7.48	6.2	0
12	5.66	5.6	0
13	1.3	1.49	0
14	2.74	4.2	0
15	6.06	8.6	0
16	5.64	7.75	0
17	8.31	11.6	1.38
18	8.54	11.6	2.16
19	7.08	10.15	.334
20	8.13	10.8	.731
21	9.01	11.4	1.586
22	4.81	8.9	0
23	3.77	5.4	0
24	1.25	....	0
25	1.55	....	0
26	3.46	....	0
27	.204	1.36	0
28	1.16	....	0
Average Samples 17 - 21	8.21	11.1	1.24

TABLE III
Core Analysis - Core #1

Sample Number	Effective Porosity (%)	Total Porosity (%)	Permeability (Millidarcys)
1	8.30	9.62	0*
2	8.15	9.62	0
3	8.05	9.39	0
4	8.17	10.04	0
5	8.55	9.62	0
6	8.16	8.17	0
7	6.42	10.21	0
Average	7.97	9.52	0

*Permeabilities are tabulated as zero when the flow rate through the core, during the permeability determination, is to small to be detected by the laboratory apparatus.

TABLE IV

Linear Displacement Test

	Sample Number					Average Samples 1, 4, & 5
	1	2	3	4	5	
Bulk Volume (cc)	9.75	9.89	10.12	10.12	10.44	....
Eff. Porosity (%)	10.3	10.4	10.5	10.2	10.3	10.3
Total Porosity (%)	12.6	13.0	12.5	12.5	12.3	....
Pore Space (cc)	1.0079	1.0254	1.0646	1.0346	1.0776	....
Dry Weight (gr)	22.5996	22.7822	23.4530	23.4772	24.2586	....
Wt. with H_2O (gr)	23.6075	23.8076	24.5176	24.5118	25.3362	....
Wt. with H_2O & Kerosene (gr)	23.4352	....	24.3401	24.3413	25.1566	....
Final Weight (gr)	23.5272	....	24.4590	24.4304	25.2567	....
Satur. at start Oil (%)	85.6	....	83.3	82.5	83.5	83.9
Water (%)	14.4	....	16.7	17.5	16.5	16.1
Satur. at finish Oil (%)	39.9	....	27.8	39.3	36.9	38.7
Water (%)	60.1	....	72.2	60.7	63.1	61.3

GAS REPRESSURING PROJECT - CLINTON FORMATION

By A. A. Coburn

GAS REPRESSURING PROJECT - CLINTON FORMATION

This paper is being presented solely as a report on a particular project in a particular area. This project may or may not be considered as a model or guide for other projects, and it is not the writer's nor his company's intention to present evidence or data to support the use of this project as a model.

Figure 1 shows the extent of our operations to date. The wells in area 1 are the wells which were drilled and had significant production prior to the initiation of the gas injection project. The cumulative production of these wells prior to the start of this project was approximately 160 thousand barrels of oil and 150 million cubic feet of gas.

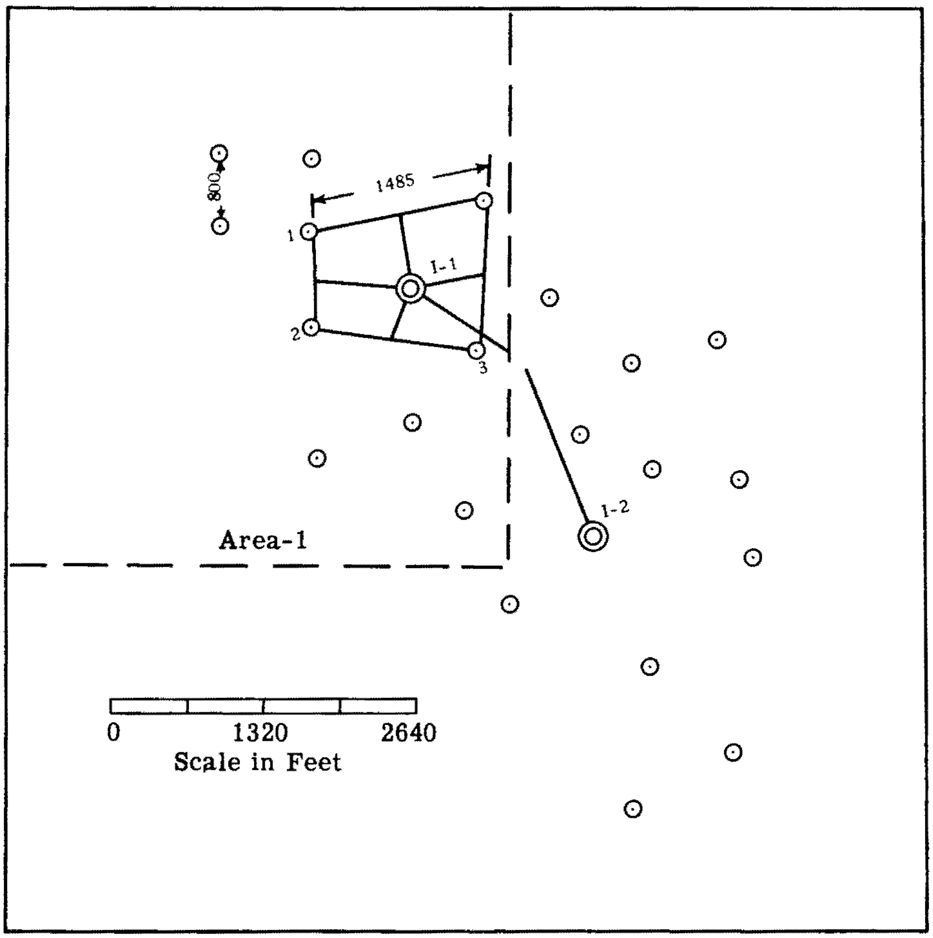

Figure 1

The well marked I-1 was chosen as the initial injection well. It was chosen primarily because it was a central well and also because it had been a good producing well. The plant was located here because of its central location.

I-2 is the second injection well chosen and has been in operation for approximately $2\frac{1}{2}$ months to date, not long enough to produce any noticeable effect on the production or operation of the field.

Figure 2 shows a Gamma Ray Neutron Log of the injection well labelled I-1. It was felt that these upper zones were primarily gas producing, and if allowed to remain exposed, would thieve a major portion, if not all, of the injected gas, thus making the project nothing more than a re-cycling operation. Therefore, a packer was run on tubing and set, as indicated on figure 2, in an effort to confine the gas to this section, which is primarily a oil producing zone. Although the gas should find its way through this zone quite readily, it should also produce some effect on the movement of oil in the zone.

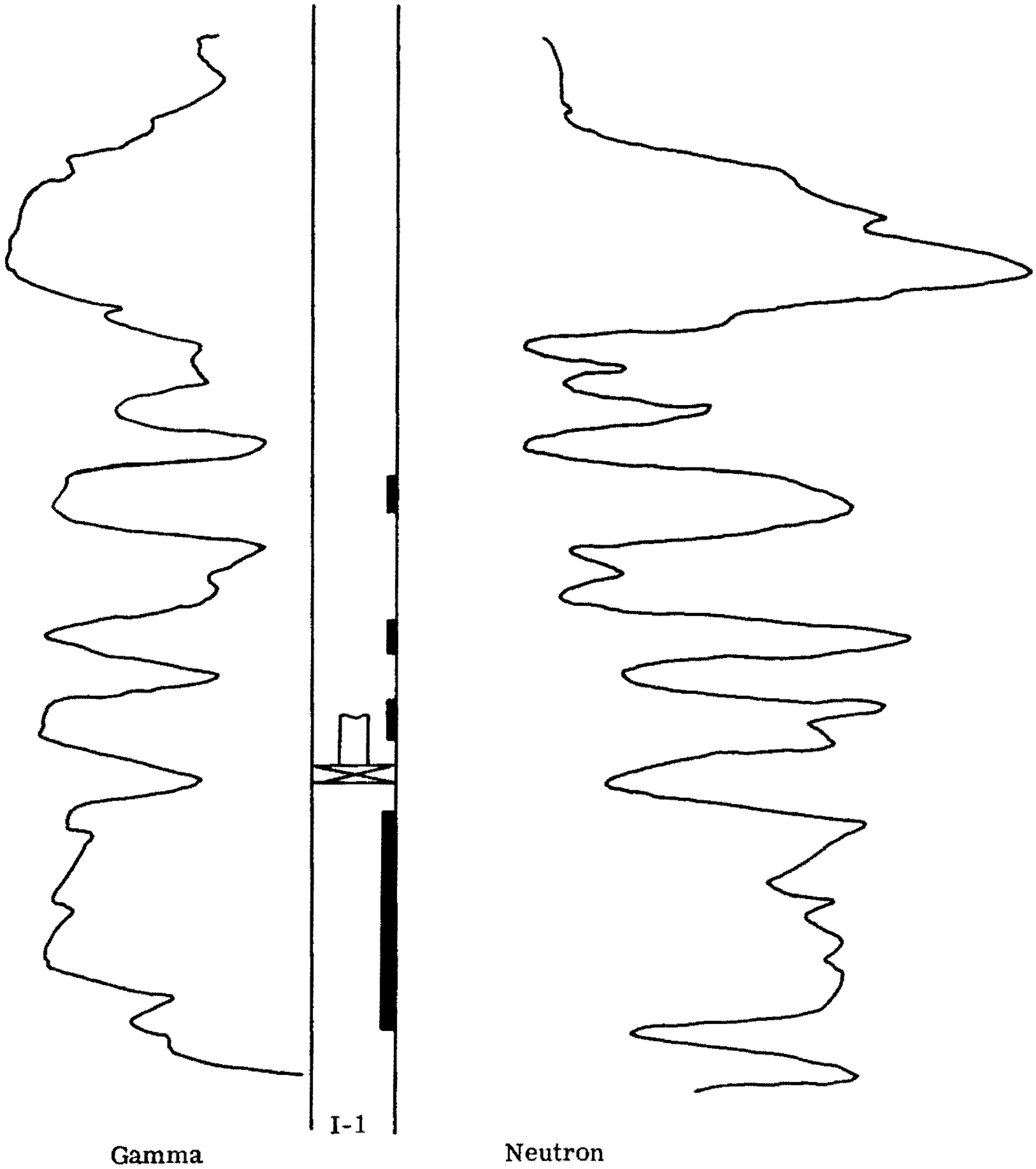

Figure 2

Although we were able to control the point of entry of the gas into the formation, unfortunately we could not control its movement once inside the formation, and consequently communication between the zones was obtained. This occurred gradually, and it was, therefore, concluded that communication was established through the formation rather than around the packer or between the casing and the formation.

No attempt is being made to control the injection in well number I-2.

The gas is collected from the separators of the producing wells and is passed through additional drips prior to entering the suction side of the compressor. It is at this point that the gas is measured by means of an orifice meter.

The compressor is a two-stage unit powered by a 100-horsepower natural gas engine. Under maximum conditions the compressor is capable of handling approximately 1 million cubic feet per day.

Injection has been continuous since its initiation, except for down time due to hydrate formation in the injection line and an occassional mechanical failure. The overall operating efficiency of the project to date is 85%. This might be improved, but it is doubtful that the success of this project depends upon this lost 15%, and it is also doubtful that the cost to increase this efficiency even 10% could be justified by increased production.

Figure 3 is a composite production curve for the three wells so numbered on figure 1. The three wells are direct offsets to the injection well and are almost equal in distance from the injection well, as well as equal in age, cumulative production, daily production, formation characteristics, and method of completion.

On the left we have the daily production, in barrels, and on the bottom the time, in months. The vertical line, in the middle of the curve, denotes the start of the injection project.

The production decline curve has been plotted for 13 months before and after the start of the project. These wells are considerably older than this, but it is not necessary to plot their complete production history for the purpose of showing the results obtained from this project.

As you can see, the production decline curve has become quite stable and well defined. The decline per well, as shown by the curve, is two-thirds of a barrel per day, per well, per month. The increases or peaks on the decline curve at and to the left of the center line were caused by a reduction of the operating pressure of the plunger lifts.

After production had hit a peak, 4 months after the start of the project, the decline curve was re-established and parallels the extension of the original decline curve.

The increase in the daily production is approximately $7\frac{1}{2}$ barrels per day, per month or $2\frac{1}{2}$ barrels per day, per well, per month. This increase has been sustained for 10 months and represents some $6,000 additional income from these three wells.

Another measure of the results obtained from this project is the continued operation of the plunger lift method of production.

Although the above results may not be overwhelming, they are significant and encouraging when you consider this project as a pilot operation. It is quite possible that when the project is expanded and altered as the past history and experience dictates, the results may become more significant.

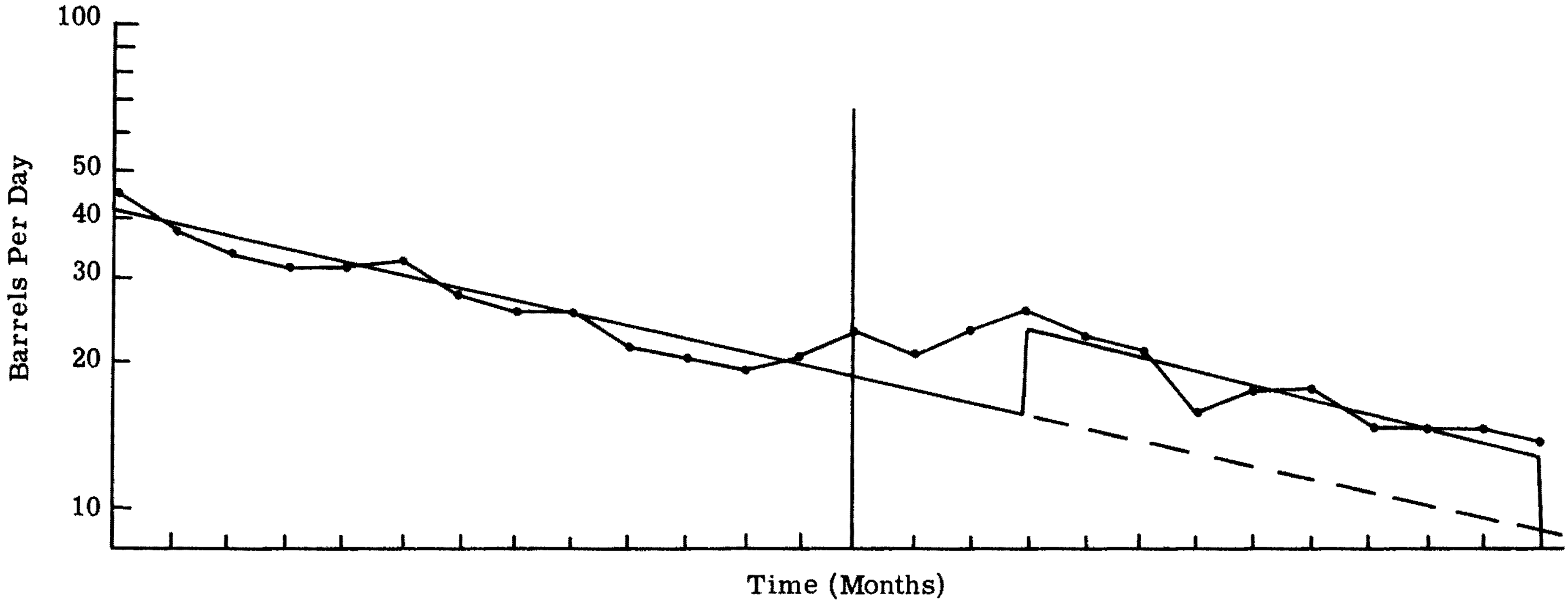

Figure 3

BIG FRAC OR LITTLE FRAC

By D. C. Hubbard

BIG FRAC OR LITTLE FRAC

D. C. Hubbard
The Ohio Fuel Gas Company

"Big Frac or Little Frac", being the title of this paper, supplies the first of many questions to be encountered with respect to treatment size. What do we mean by big or little? No doubt, we all have our own definition for these terms as they relate to stimulation by the hydraulic fracture method. Inasmuch as I am presenting this paper, I shall use the author license and apply my definition to these terms.

Engineering wise sand-fluid volume should relate to the thickness and radial area of the pay zone, and therefore, the term big or little would vary accordingly. Relative to our own area, we are working with thin pay zones of uncertain radial extent in conjunction with limited reservoir data. It is therefore necessary to apply historical data as a critera for differentiating big from little. Treatments today vary from 1000 gallons of fluid carrying 2000 pounds of sand to 35,000 gallons of fluid carrying 30,000 pounds of sand. The average being approximately 10,000 gallons of fluid and 10,000 pounds of sand. Considering varying factors, I prefer to classify anything less than 8,000 pounds of sand as a "little" treatment and those in excess of 12,000 pounds of sand as a "big" treatment. The range between eight and twelve thousand pounds would remain a gray area dependent upon other influencing factors.

Since the inception of hydraulic fracturing as a medium of well stimulation, the pro's and con's of treatment size have been discussed and debated by those interested in fracturing. Treatment size, being only one facet of the operation, causes some question in my mind as to the significance of size as the governing factor in the relative success of a treatment.

Prior to evaluating the merit of large or small treatments, one must first consider the other factors present which can appreciably affect the resultant. These factors will vary with respect to formations being evaluated, therefore, for our purposes we must consider the Clinton formation, which has been Ohio's most prolific producers, and the one which has most favorably reacted to hydraulic fracturing.

The first and most significant of these factors is the ultimate recoverable reserves which can be produced from the formation in question. Although it is questionable that any of us have reached the point where we have adequate technological data to accurately project such a figure, there is historical data which will suffice by supplying an average figure. In evaluating this figure, it has been stated that through fracturing the recoverable reserves may be increased since increased flows permit our utilizing reservoir pressure to point which in many cases was not economically feasible in the past. It will be noted that I used the phrase may be increased. The reason for such a statement is that increases realized through fracturing as related to historical data must be tempered to some degree because of conditions affecting such data. I believe that we all agree that prior to fracturing,wells being utilized had initial open flows which were higher than those being completed today. Considering this, it is logical to assume that there is a similarity between present recoverable reserves and those arrived at from past history and it would therefore be unwise to base economic production studies on an increased figure.

A second factor of importance is the completion practices used in preparing the well for stimulation. Has the well been completed for selective fracturing, open hole treatment, or one zone entry? These factors will certainly affect the size of treatment plus the well economics.

The third factor is the reservoir itself. Are we dealing with a series of pay zones definitely separated by shale sections, or a single zone? Are these pay zones thin or thick? What is the porosity, and the existing permeability? Although we can, through logging, determine answers to these questions, they are nevertheless factors which affect the size of the treatment. In addition to determining the treatment size the acquisition of the data is an item of cost which again influences the well economics.

In conjunction with the reservoir data mentioned, another of importance is radial area to be drained by the well in question. Since the Clinton is noted for its complexity, this is a factor which I believe is nearly impossible to evaluate. This is the reason I initially discussed using average recoverable reserves as a method of evaluating the wells ultimate. Logging and the application of logging data may eventually supply a better tool of evaluation, but considering the extent the Clinton has been developed, this is questionable.

The fourth influencing item pertains to the related fracturing mechanics. Such items as size of injection strings, injection rate and chemical additives can generally be evaluated through engineering studies.

As will be noted, the factors discussed pertain to both the mechanical and economic success of a fracture stimulation. For our purpose I believe that we should bypass the mechanical aspect of success and investigate the economic value realized. I think that we will all agree that in a majority of treatments the flow of a well is increased, but that the economic success of the well is not so readily realized.

I realize that I have discussed several items and factors regarding fracture without mentioning the merit of a large or small treatment; but, I feel that this is necessary to substantiate the position I have taken with respect to treatment size. Each factor either contributes to the mechanical or economic success of the treatment and therefore must be evaluated along with the treatment size.

First and of most importance is the fact that under present conditions we are unable, at time of completion, to determine recoverable reserves. Considering this, we must use the average which from past history is approximately 130 million cubic feet for a Clinton well. Regarding oil wells the average is not available; but, like gas wells is a relatively low figure, in the range of 15 to 20 thousand barrels. Since these relatively small reserves prevail, completion costs must be in relation. Treatment cost being a function of size must therefore be considered.

As previously stated, type of completion is a factor in determining treatment success. It is also a factor with respect to the size of treatment. It is possible that by cementing through and perforating individual pays, treatment of several zones would be advisable, but, again the economics must be considered in relation to the results realized. Do the results realized from multiple zone treatments equal the cost?

You will note that my entire discussion up to this point, has resulted in how the treatment affects the economics of completing the well. The question remaining is the economics of producing the well. It is generally conceded that treatment size is a function of the initial flow realized, but, I believe we all agree that increases realized is not proportionate to increases in treatment size. It can also be noted from production data that the larger the treatment the sharper the initial decline. Does the initial increase render adequate production prior to approaching normal decline to offset the additional cost?

Mechanics of fracturing is an area which has presented the most unknowns, the greatest number of theories, and required the most research. Although hydraulic fracturing has been greatly improved through research, with respect to carrying mediums, chemical additives, injection rates, and improved equipment, I do not believe that we have any answer to the ideal treatment size. Our service companies are definitely approaching an answer, but prevailing conditions make it extremely difficult. These conditions are the lack of reservoir engineering data, the cost of acquiring same, the complexity of our formations. Again the discussion ends with questions. What portion of the fracturing benefits result from correcting bore hole damage? Are we acquiring horizontal or vertical fracture? What portion of the treatment is effective? Do we benefit greater from the initial fracture or from extended fracture? There are laboratory answers available to many of these questions; but, in my opinion are not yet applicable to our area of operations.

In order to answer the multitude of questions which exist, relative to the factors influencing hydraulic fracturing, we must first determine what is to be realized.

I believe that we all concur that the ultimate is to cause a well to be an economic success by increasing its productivity. With this as the controlling factor, all aspects of stimulation must be related not only as a productivity accelerator but also as a cost element.

Having such a multitude of producers in this area has made it difficult to arrive at a set of standards which are applicable to all concerned. Because of this, I have chosen to evaluate these questions and cost elements as they relate to our operations in The Ohio Fuel Gas Company. I am not implying that our conditions, methods of operations, construction costs, and results realized are applicable to all producers but only attempting to set forth those items which we all must evaluate.

Our first item of concern is what can we ultimately recover from a well and the time required for such recovery. As previously stated, the average recoverable reserves from a Clinton well are approximately 130 million cubic feet recoverable over a period of 20 years. Being cognizant of our construction and operational costs, it is evident that we are working with a limited margin of profit. Controlled by this factor, all future decisions must be carefully scrutinized, relative to the results realized from the dollar expended.

Having set forth a primary control, I will attempt to answer the questions resulting from my prior discussion.

Determination of the reservoir is of course an important factor in both the size and success of the treatment. The pay zones and their related significance must be determined prior to stipulating type of completion and size of treatment. The drillers' logs will generally suffice when open hole completion is to be used, but is not adequate for selective multiple zone completion. Acquisition of the data necessary to carryout such selective fracturing requires electrical and radiation logging - an item which will require expenditures. The amount of these expenditures will vary; but, in order to do a complete job the construction cost of the well will be increased approximately 4 percent.

Regarding completion as it pertains to facilitating fracture, one must evaluate the benefits and costs to be derived from the type of completion to be used. By cementing casing through the productive horizon and perforating the various pay zones, preparatory to multiple zone treatments, we have no doubt set forth conditions necessitating larger treatments. But, we have also increased completion costs to a point which will increase overall construction by approximately 9 percent - a significant item when related to the marginal aspect of an average well.

In order to perform a multiple type stimulation, which would substantiate a larger treatment, we have increased construction costs approximately 13 percent. Some wells would no doubt warrant this type of treatment; but, as previously stated, our present data does not offer a sufficient recoverable reserve figure to predict the value of each zone. It is our opinion that an open hole treatment will generally enter the zone of highest permeability and therefore, effect the better of the zones. Also influencing our decision regarding the use of multiple zone treatment is the fact that although initial increases are from 30 to 50 percent higher, the accompanying decline is proportionate. Data is limited, but from that which is available, with respect to gas, the production recovered prior to reaching the decline of open hole stimulation is approximately 4 million per well. Each well having individual characteristics makes it difficult to compare these figures, but since the results are not indicative of significant increases, it is difficult to substantiate the multiple zone type of treatment for gas wells.

When independent zones are productive of oil and gas respectively, it is possible through careful evaluation of the initial flows and pay thickness to benefit from multiple zone treatments.

Evaluation of treatment size, when utilizing open hole completion, has only one critera that can be employed to determine merits of big or small treatments. This being the economics of the treatment.

By analyzing treatments, it has been noted, that increases rendered by the large treatments are only 25 percent higher initially than the results of the small treatments. This equates to an 8 fold increase for the small treatments and a 10 fold increase for large treatments. In conjunction, the severity of the decline for large treatments is proportionately greater and after approximately 15 days of delivery, the two curves meet. It is difficult to compare treatment size when each well differs with respect to reservoir conditions; but, from available data, the larger treatments are resulting in only 10 percent increased delivery prior to reaching the decline of smaller treatments. Overall, this amounted to only 2 million cubic feet of produced gas.

Substantiating our theory, that economically speaking, our results are better from small jobs, we have on four occasions followed up 2 thousand pound treatments with treatments of 4 and 6 thousand pounds with no appreciable increase.

The correction of bore hole damage caused by drilling operations is an important benefit of fracturing that can be readily realized through a small treatment. We have on several occasions treated wells with as little as 500 pounds of sand and the results have been very beneficial. A job of this size could not effect extended fractures to any degree, therefore, the benefits were the result of the initial fracture and the correction of bore hole damage.

Also to be considered is the actual disbursement of the sand. Since we are not certain of the type of fractures, with respect to vertical or horizontal, it is impossible to determine the effectiveness of the sand used.

As previously stated, the factors discussed are evaluated as they effect the operations of the Ohio Fuel Gas Company and are not necessarily sound with respect to all operators. But these items are prevailing in all instances and in some manner must be considered.

To reiterate, many of the factors influencing treatment size are based upon unknown or historical data and could certainly be altered through the realization of factual information. The service companies are advancing along these lines and it is possible that in the future treatment size can be determined through technological data.

In summary, it is my opinion that until such time as we can, through experience, substantiate large volume sand-oil treatments as being economically feasible, we will continue to use small treatments.

COST CUTTING WITH CABLE TOOL DRILLING

By Berman J. Shafer

COST CUTTING WITH CABLE TOOL DRILLING

INTRODUCTION

Cable tool drilling, the original method of drilling for oil and gas in the United States, is still in popular use east of the Mississippi River, where there are approximately 1500 cable tool units operating. There are several reasons for this majority of table tool units:

(1) Low pressure shallow pays. Operators in the Appalachian basin are accustomed to producing in low-pressure formations of which there are many. By penetrating these zones with a cable tool bit, the operator is able to inspect visibly what production he encounters without danger of mudding off a pay with a mud filter cake.

(2) Relaxed schedules. Operators in the Appalachian area are not particularly concerned with the element of completing wells within a certain time. Bank financing for production in eastern areas is rarely found, and independent operators do not find it a necessity to complete a well quickly.

(3) Lower cable tool investment. Rotary-type drilling operations, at the present time, are more costly than cable tool. Although certain sizes of casing are eliminated in rotary operations, contracts are higher in costs. This of course is due to the fact that rotary equipment entails a higher initial investment. However, it is conceivable that more drilling experience, prudent operation, and the increased use of air as a drilling fluid will result in rotary-type drilling competing with cable tools.

(4) Operators' cost consciousness. Appalachian area operators have become quite cost conscious because the average productivity per well is less at present producing levels than that found in other areas. Therefore, there is a greater need for keeping costs down to achieve maximum profits.

METHODS OF COST CUTTING

In order to maintain footage costs as they are in the face of rising equipment expenses, the cable tool contractor is confronted with the problem of cutting his costs. The costs of equipment and supplies have increased far greater than footage contract figures. Since the contractor has little control over the costs of steel goods, he must look to cutting other costs of operation for which he is directly responsible. These are (1) labor costs, (2) supervision, (3) maintenance expense, (4) fuel, (5) cordage, (6) overhead and administration, (7) tool replacement and repair, and (8) insurance and workmen's compensation.

Labor costs are a contractor's principal expense item on a cable tool rig. The qualities of a good driller are not only that he makes the most footage but also that he is responsible for the best care of the rig.

Maintenance expense involves the use of proper lubricants for bearings and other movable parts. It is also important that lubricants be kept free of dirt and grime before application.

Tool replacement and repair has become a major expense item. A relatively recent development in alloy steels used in drill bits, drilling jars, and stem joints has lengthened their life and lowered the rate of fishing jobs. Electric welded stem joints have also cut costs to the contractor by taking the guesswork out of drill stem construction. A fishing job is caused by drillers' neglect, faulty stem welds, joints, or a break in a drilling or sand line. There are various fishing tools manufactured to recover lost tools, but in some cases special tools must be machined to do the job. Fishing jobs can be a major expense in a driller's ledger of costs, but proper use of stem joints, care of wire cable, and proper drilling techniques can avoid a majority of fishing jobs.

Cordage can be a major expense to the cable tool contractor inasmuch as the wire line is used for drilling tools, the bailer, and as a casing line. Failure to care for a wire line can only result in fishing jobs and a short line life. Undue bending, kinking, fatigue, and localized wear are the principal reasons for poor wire performance. Most manufacturers of drilling cable put into print the proper field care and use of wire rope, and it is important that this literature be read to field men who handle wire cable.

Insurance. Most public liability policies, as well as State industrial insurance, are based upon annual payrolls, which amount to a sizable figure in Ohio. It is unfortunate that cable tool contractors have not carried out a safety campaign as found in the southwest areas of the United States, where safety programs are emphasized as a very important phase of a drilling crew's work day. A suitable safety program should be foremost in the mind of cable tool contractors to lower insurance rates.

CABLE TOOL EQUIPMENT

Aside from the direct costs mentioned above, there has been little accomplished over the past few years in the modernization and remodeling of cable tool equipment. It would appear that there would be a greater demand for cable tool equipment if the manufacturer would have a representative spend a period of time interviewing contractors to determine their needs and contributions to the design of a drilling machine suited to the field man.

Furthermore, it is noted that this area is without the services of a staff of trained mechanics employed by the manufacturers to call in the event of equipment breakdown. As a result, the driller, the toolpusher, or the local mechanic must be able to repair with the usual collection of tools any equipment that fails.

Consequently, a great deal of time is consumed in diagnosing the source of the trouble, as well as in repairing the trouble.

A piece of equipment capable of drilling to depths of 3000 to 4000 feet with a cost of over $30, 000 should have a central lubricating system. Also, experience has shown that storage capacities of the bull reel and sand reel are not in line with the rated capacity of the machine. The result of this has been to compact all reels into a box frame allowing little or no provision for repair in the field in the event of a part failure.

CONCLUSION

In the coming years there will be a trend toward sinking deeper tests to 6000 feet and more, using rotary equipment rather than cable tool. Although these tests have been few to this date, it is logical that more drilling experience to these depths will pave the way for more rotary operations. With this added competition, the successful cable tool contractor will be the one who has found the way to lower his costs.